

**Developing Methods to Identify Unstimulated and/or Ineffectively  
Stimulated Reservoirs Resulting from Multi-stage Hydraulic  
Fracture Treatments**

during the Period 05/15/2002 to 11/30/2002

By

Gerald W. Merriam, Walter K. Sawyer, P.E., and Joseph H. Frantz, Jr., P.E.  
**Schlumberger Holditch – Reservoir Technologies**

November 2002

Work Performed Under Prime Award No. DE-FC26-00NT41025  
Subcontract No. 2041-HRT-DOE-1025

For  
U.S. Department of Energy  
National Energy Technology Laboratory  
P.O. Box 10940  
Pittsburgh, Pennsylvania 15236

By  
Schlumberger Holditch - Reservoir Technologies  
1310 Commerce Dr.  
Park Ridge 1  
Pittsburgh, PA 15275-1011

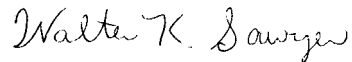
**DEVELOPING METHODS TO IDENTIFY UNSTIMULATED  
AND/OR INEFFECTIVELY STIMULATED RESERVOIRS RESULTING  
FROM MULTI-STAGE HYDRAULIC FRACTURE TREATMENTS**

*prepared for*  
Stripper Well Consortium  
Pennsylvania State University  
University Park, Pennsylvania



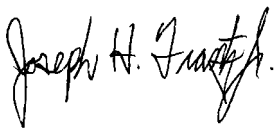
---

Gerald W. Merriam  
Senior Engineer



---

Walter K. Sawyer, P.E.  
Principal Consultant  
Reservoir Simulation



---

Joseph H. Frantz, Jr., PE  
Eastern U.S. Operations Manager  
Division Manager

**November 2002**

---

## Table of Contents

<b>1</b>	<b>EXECUTIVE SUMMARY.....</b>	<b>2</b>
<b>2</b>	<b>INTRODUCTION.....</b>	<b>4</b>
<b>3</b>	<b>CONCLUSIONS .....</b>	<b>8</b>
<b>4</b>	<b>RECOMMENDATIONS.....</b>	<b>9</b>
<b>5</b>	<b>DISCUSSION OF RESULTS .....</b>	<b>10</b>
5.1	LITERATURE SEARCH.....	10
5.2	PROCESS PROCEDURE.....	10
5.3	MEMORY PRODUCTION LOGGING .....	10
5.4	FRACTURE GEOMETRY.....	13
5.5	TEST WELL.....	14
5.6	INJECTION/FALLOFF TEST SIMULATION .....	15
5.7	INJECTION/FALLOFF TEST.....	16
5.8	HISTORY MATCH OF INJECTION/FALLOFF TEST AND PRODUCTION DATA.....	19
5.9	RE-STIMULATION OF THE UPPER BEREA .....	21

### APPENDIX A

### APPENDIX B

## List of Tables

Table 1 – Summary of Memory Production Log Analysis Results .....	6
Table 2 – Recompletion Candidates .....	7

## List of Figures

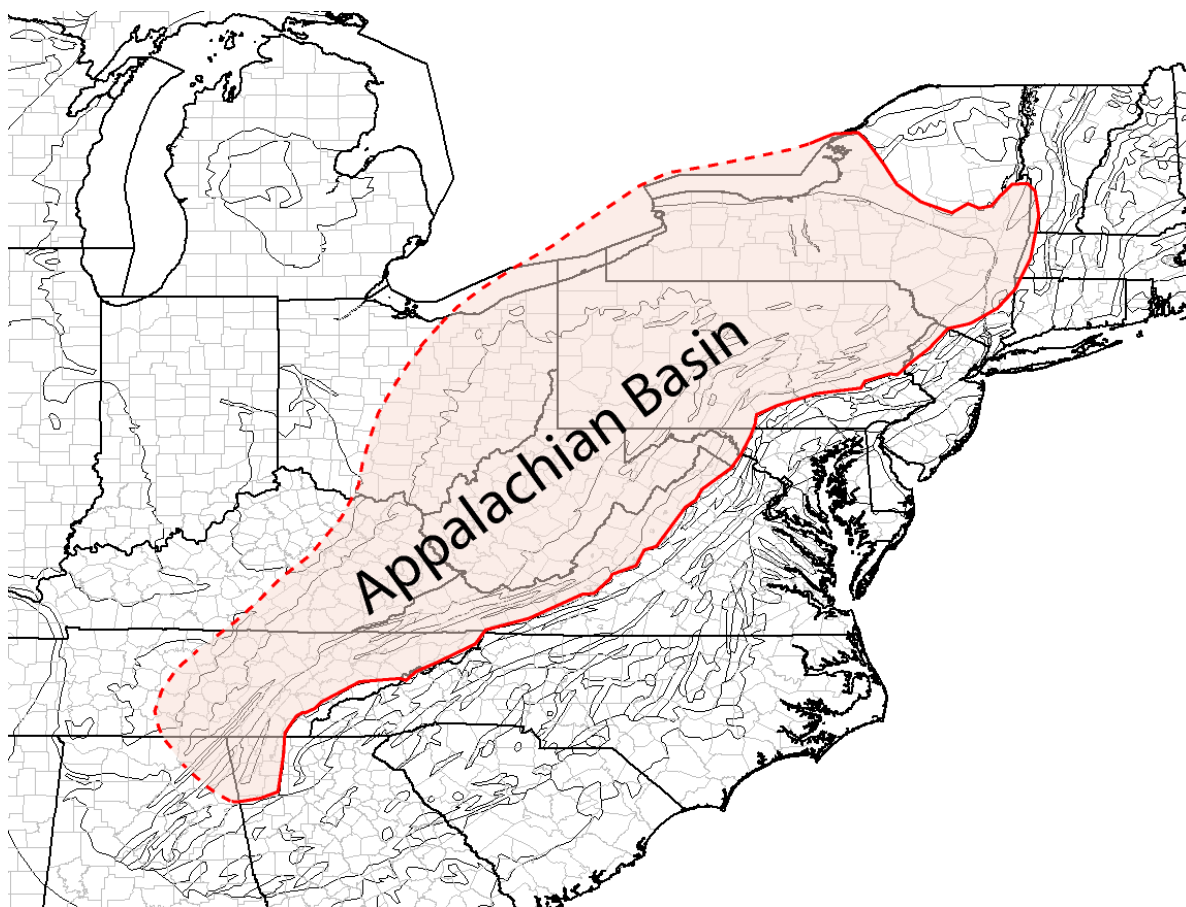
Fig. 1 Appalachian Basin map. ....	2
Fig. 2 Multi-stage treatments can result in uncertain stimulation effectiveness. ....	4
Fig. 3 MPL clearly identifies gas, water and/or oil entry into the wellbore.....	11
Fig. 4 MPL showing fluid level in Lower Devonian Shale.....	12
Fig. 5 Multiple fractures created.....	13
Fig. 6 One fracture created.....	14
Fig. 7 Ford Motor Company #165 MPL section through Berea.....	15
Fig. 8 Simulation of injection/falloff test in Upper Berea.....	16
Fig. 9 Ford Motor Company #165 prepared for injection/falloff test. ....	17
Fig. 10 Ford Motor Company #165 well schematic during injection/falloff test. ....	18
Fig. 11 FMC #165 injection/falloff test bottomhole pressure. ....	18
Fig. 12 History match of injection/falloff test.....	20
Fig. 13 History match of Upper Berea production. ....	21
Fig. 14 History match of Upper Berea after restimulation. ....	22

## **DISCLAIMER**

*This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.*

## 1 Executive Summary

This report summarizes an evaluation performed by Schlumberger Data and Consulting Services (DCS) and Equitable Production Company (Equitable) regarding the area of reservoir remediation, characterization, and operations. Several groups of Equitable's Appalachian Basin wells in West Virginia (WV) and Kentucky (KY) were used in the study. The objective of this project was to identify unstimulated and/or ineffectively stimulated reservoirs in stripper wells treated with multi-stage hydraulic fracture treatments. Multi-stage involves pumping two to four hydraulic treatments in a well with many low-permeability formations perforated and open to each treatment. Multi-stage treatments are common in the Appalachian Basin (**Fig. 1**) and in many low-permeability wells across the U.S., because multiple sand, shale, and carbonate reservoirs often occur over a thick, stratigraphic interval. Based on our experience, it is unlikely that all perforated intervals are treated effectively when performing multi-stage stimulation treatments due to the large gross interval open in the wellbore.<sup>1</sup>



**Fig. 1 – Appalachian Basin map.**

Using existing data and by collecting new downhole diagnostic data, we determined the extent of stimulation in a perforated interval in a study well provided by Equitable Production Company (EPC). The well is located in Pike County, Kentucky. The downhole diagnostic data includes memory production log (MPL), isolation tests, injection/falloff tests, hydraulic fracture data analysis, and production data analysis. We determined the interval was ineffectively stimulated because it was non-productive, but showed good log responses. An injection/falloff test was performed and showed the perforations were open, the reservoir pressure was low, and there was a fracture in the zone. A decision was made to restimulate the interval since the pumping equipment was on-site and it would therefore be a minimal cost. The well was thus restimulated with a nitrogen treatment since the well was originally completed using nitrogen stimulations. A history match of post-production indicated that the restimulation probably created a wider fracture with the same initial length. This slightly improved performance. It is uncertain how long this fracture will remain open or what width it may retain due to the lack of proppant. Many operators in the Appalachian Basin have switched to this method as the fluid of choice over the past ten years.

This well was a poor restimulation candidate due to the low reservoir pressure (190 psi) and the existence of a fracture (100 feet length and .00045 inches wide). The restimulation did increase the width of the fracture from 0.00045 to 0.00605 inches, but did not increase the length of the fracture. The well production improved from too small to measure to 6 Mscf/D, but the production will continue to decline and the zone has an estimated recovery of 14 MMscf. At an approximate cost of \$30,000 this restimulation was uneconomic.

An evaluation methodology was developed for use by any Appalachian Basin operator to determine which formations were ineffectively stimulated with past treatments. We anticipate that this methodology will also be useful for other operators throughout the United States where multi-stage treatments are pumped.

Ultimately, we believe that this work could result in a paradigm shift for operators. If they understand that certain formations were not stimulated and/or not effectively stimulated, they will restimulate these formations in existing stripper wells. This project could result in substantial new production from stripper wells for Appalachian Basin operators. Given the currently high value of natural gas (>\$4/Mscf), even very low flow rates (5 Mscf/D) resulting from restimulations may be economic. Operators may also change their field stimulation procedures in new wells to treat all formations more effectively.

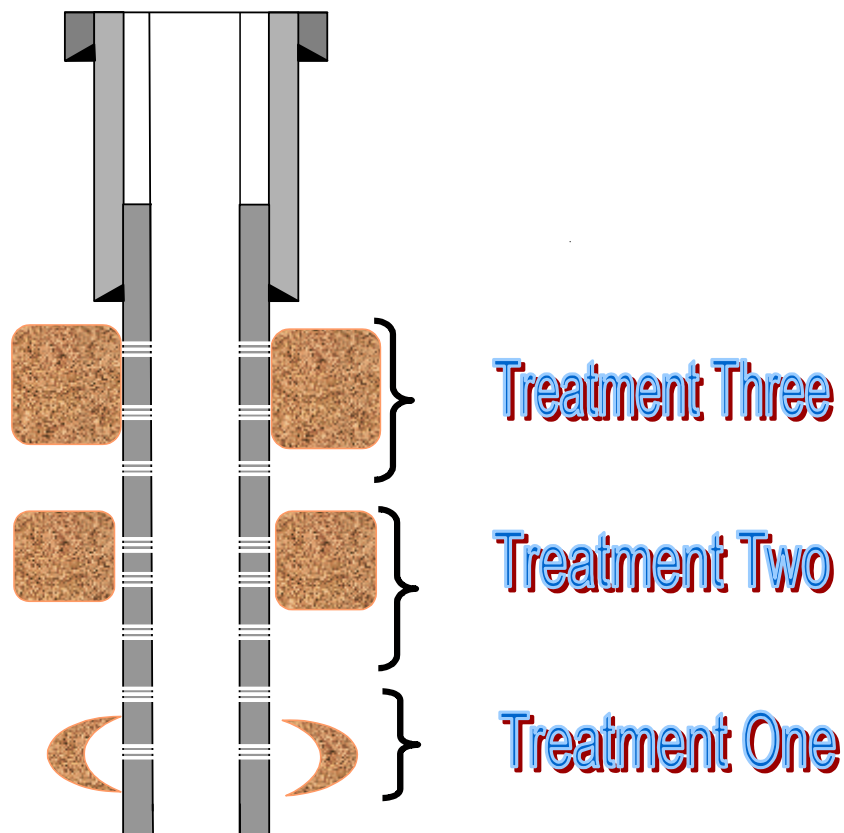
The potential benefit to the Appalachian Basin stripper well community may be significant. We believe that about 75% of the 66,000 stripper wells in Pennsylvania (PA), WV, and KY were stimulated with multi-stage treatments. We estimate that 50% of these (about 25,000 stripper wells) may have restimulation potential, but only half of them (12,500 wells) may be in sound mechanical condition for restimulation. If the restimulation treatments result in a 5 to 10 Mscf/D production increases per well, the overall significance to the Appalachian Basin is large. We estimate a potential impact to the Appalachian Basin of 94 MMscf/D or 34 Bscf/year if all the mechanically sound stripper wells in PA, WV, and KY were restimulated. This represents a 20% increase in the current total stripper well gas production level in these 3 states. This could represent \$137 million in new revenue.

While the cost to run a MPL, isolate a zone, perform an injection/falloff test, fracture stimulate the zone, and analyze the data is dependent on several factors such as size of treatment, depth of well, equipment requirements, etc. it is estimated that a typical Appalachian operation would cost \$25,000. Assuming an incremental increase of 10 Mscf/D, a royalty of 12.5%, and a gas price of \$4/Mscf it would have a payout time of less than two years.

## 2 Introduction

Most wells in the Appalachian Basin (and throughout the United States) are stimulated with multiple hydraulic fracture treatments. This is necessary because multiple low permeability reservoirs often occur across a thick, stratigraphic interval. In the Appalachian Basin, the formations include the Devonian Shale, the Upper Devonian sands, and the Mississippian sands and carbonates. It is not uncommon to perform two to four hydraulic fracture treatments over a gross interval greater than 1,000 ft. The number of perforated intervals is even more extensive ranging from four to 10 in a typical Appalachian Basin well. This means that several formations are open at the same time in each of the stimulation treatments.

The problem with current multi-stage practices is the uncertainty in which intervals were effectively stimulated, **Fig. 2**. Most operators have several stimulation treatments performed in one day to reduce the cost per stimulation. It is unknown which perforations accepted the treatment and the overall fracture geometry. After the treatments, it is rare for an operator to perform any analysis to determine how many of the formations were stimulated, let alone evaluate the stimulation effectiveness in the intervals that accepted the treatment.



**Fig. 2 – Multi-stage treatments can result in uncertain stimulation effectiveness.**

Other problems exist with current multi-stage treatments. Many operators use the ball and baffle method as a means to isolate each new treatment interval in a multi-stage treatment when pumping nitrogen-foam and proppant. When they are ready to perform the next treatment a frac ball is dropped and then pumped downhole usually with the acid to be used on the next stage. This ball seats on a baffle, present in the casing, and isolates the zone. It is difficult to predict the actual required displacement due to the compressibility of the foam fluids ahead of the acid and is suspected that many of the treatments are overdisplaced. To our knowledge in the Appalachian Basin, it would be rare for an operator to perform a post-fracture test to evaluate the near-wellbore fracture conductivity after a treatment has been possibly overdisplaced.

Due to low reservoir pressures and concerns of water sensitivity, many wells especially completed in the Devonian Shale are fractured stimulated using straight nitrogen without proppant or liquids. These nitrogen-only treatments also result in an uncertain fracture conductivity, fracture half-length, fracture height, and overall stimulation effectiveness. The industry is uncertain which intervals are treated when multiple intervals are open during a nitrogen treatment. The resulting fracture geometry from nitrogen stimulation treatments is one of the largest unknowns in the industry. Previous GRI research has shown that thin, low viscosity fluids may stay in zone. Nitrogen is a low viscosity gas; therefore it may indeed stay in zone, and not treat many zones vertically in the wellbore. If one perforated interval accepts all or most of the treatment, the other perforated intervals may remain untreated or be ineffectively treated.

Finally, previous industry research has shown that stimulating naturally-fractured, low permeability formations can result in highly variable hydraulic fracture geometries<sup>2,3</sup>. The Appalachian Basin stripper wells fall into this category since they are completed in naturally-fractured, low permeability reservoirs. For example, an interval that is very naturally-fractured may take all the treatment. The perforation scheme and breakdown may also affect where the treatment enters. Additionally, treatments may not grow vertically for extended distances due to complex natural fractures, i.e., the growth of hydraulic fracture may stop at lithology changes where natural fractures terminate<sup>3</sup>. There is a concern over which intervals accept the treatment and the resulting hydraulic fracture geometry.

A literature search was initiated to determine what if any studies were done on the above subjects. Searches were performed on selected terms: multistage fracturing, nitrogen fracturing, field testing, restimulation, testing. Two hundred sixty ± abstracts, reports, or papers were reviewed. Seventy-seven of the more relevant abstracts, reports, or papers are listed in Appendix A. Twelve of the records had some bearing on this study and are listed first in Appendix A.

Equitable had previously run over 40 memory production logs. Memory production logs are run on slick lines with the logging data stored in downhole memory and played back on location after tools are retrieved from the well. This produces a log equal to that of surface readout with less equipment and manpower. **Table 1** shows the thirty-one memory production logs reviewed to determine what zones are and are not producing. These were compared to the openhole logs in an attempt to determine if nonproductive zones should have been productive if effectively stimulated.

**Table 1**  
**Summary of Memory Production Log Analysis Results**

Well Name	Completion Zones	Measured Flow	Percentage of Gas Production per Zone							
		During P/L, Mscf/D	Ravenscliff	Maxton	Big Lime	Weir	Berea	Gordon	Upper Shale	Lower Shale
Ritter #348	G/B, BL, Rav	234	11		66		23 (G/B)			
Pocahontas/Carnegie #2	LDS, UDS, BL	92			40				20	40
Pardee Land #93	LDS, UDS, B/W, BL	380			12	3	70		10	5
Hinchman #B-2	LDS, B/G, W/BL, Max	120		20	35	0	0	35	10	0
Ritter #235	Rav,Max,G,UDS,LDS	85	80	0				10	0	10
Elk Creek Coal #36	BL,B,UDS,LDS	157			35		35		20	10
Island Creek #D-86	W/BL,UDS/G/B,LDS	275			80	5	0	0	12	3
Elk Creek #42	BL,B,UDS,LDS	203			20		23		37	20
Coal & Crane B-26	BL,B,UDS,LDS	66			20		30		47	3
David Francis Trust #4	BL,B,UDS,LDS	80			0		40		52	8
David Francis Trust #5	BL,B,UDS,LDS	68			20		20		55	5
Thacker Land A-7	BL,W/B,UDS,LDS	80			20	0	0		70	10
Island Creek #D-29	BL,B,UDS,LDS	155			60		10(UDS)		*	30
EPC Hall W.D. KF 4427	B/W,B,UDS,LDS	108				15			77	8
EPC John Godsey #1 KF 918	B/UDS,LDS	77					100(UDS)		*	0
Gibson E 2KL 1446	BL,B,UDS,LDS	71			20		0		30	50
Harve Johnson KF 4448	BL,B,UDS,LDS	68			18				58	24
W.D. Hall KF 1604	W,B,UDS,LDS	50				15	0		75	10
Rouge Steel #2	B/LDS	89					60			40
Ford Motor 1-094	BL,B,UDS,LDS	190			10		80(UDS)		*	10
Smith Carrs Fork 2-1	BL,W/B,UDS,LDS	82			10	0	70(UDS)		*	20
Hatcher 4-105	BL,UDS/B,LDS	57			0				50	50
Hatcher 4-060	BL/B,B,UDS,LDS	15			30				65	5
Republic Steel 2-108	Max,B/UDS,LDS	Due to large volume of fluid was unable to acquire accurate interpretation								
Colony C&C 2-101R	BL,B,UDS,LDS	130			10		50(UDS)		*	40
Chesapeake Mineral 2-051	BL,B,UDS,LDS	100			0		70(UDS)		*	30
Emperor Coal 1-285	BL,B,UDS,LDS	72			55		25(UDS)		*	20
Ford Motor 165	B/UDS,LDS	40					80(UDS)		*	20
Chesapeake Mineral B-39	BL,B,UDS,LDS	25			80		10(UDS)		*	10
Republic Steel #79	B/UDS,LDS	38					60(UDS)		*	40
S. Coleman 2-018	Max,BL,B/UDS,LDS	220		25	10		42(UDS)		*	23
* In most of the Kentucky wells, the Berea is completed with the Upper Devonian Shale.										
LDS – Lower Devonian Shale		W – Weir								
UDS – Upper Devonian Shale		BL – Big Lime								
G – Gordon		Max – Maxton								
B – Berea		Rav – Ravenscliff								

This review resulted in 10 of the 31 wells containing zones that were either not producing or producing less than the openhole logs would indicate. Thus, these 10 wells are possible candidates for restimulations as shown in **Table 2**.

**Table 2**  
**Recompletion Candidates**

Well Name	Recompletion Zone	Comments
Pocahontas/Carnegie #2	Upper Devonian Shale Lower Devonian Shale	Several zones in shale not producing
Hinchman B-2	Berea, Weir, Big Lime	Zones not producing
Island Creek D-86	Berea	Very little production
Thacker Land A-7	Berea	Not producing
Gibson E 2KL 1446	Upper Devonian Shale	Lower perforations in Upper Devonian Shale not producing
Harve Johnson KF 4448	Berea	Not producing
Smith Carrs Fork 2-1	Weir	Not producing
Hatcher 4-105	Big Lime	Dolomite zone not producing after acid treatment
Hatcher 4-060	Big Lime	Dolomite zone acidized producing little gas/oil
Ford Motor 165	Upper Berea	Not producing

Most of the wells were stimulated using nitrogen without proppant. Fracture modeling was performed to determine theoretical fracture width and length. This modeling was performed using the MFrac™ software by Meyer & Associates, Inc.

A simulation model using SHALGEGAS™ has been built to evaluate what type of nitrogen injection test can be used to determine if an interval has been fracture stimulated. The model is set up to simulate both injection/falloff tests and gas production for nitrogen fractures of various aperture widths.

### 3 Conclusions

- Memory production logs are useful in determining the relative amount of gas flowing from each interval.
- Comparison of these production logs versus the openhole log can determine what zones are producing less than expected.
- Modeling of nitrogen fracture treatments indicates very narrow and short fracture lengths, especially if multiple-fractures are developed.
- Simulation using SHALEGAS™ indicates that even the small fracture widths created by using nitrogen fracturing can be detected using injection/falloff testing.
- Field injection/falloff testing will be required to determine if these non-productive, or lower than expected productive zones, were effectively stimulated.
- Most of the wells had fluid levels in or above the Lower Devonian Shale.
- This fluid was negatively affecting production as demonstrated by the production increases in many of the wells after swabbing to remove the fluid.
- Quicker, lower cost and more efficient methods to evaluate the effectiveness of stimulation are needed.

## **4 Recommendations**

The following methodology should be used to identify unstimulated or ineffectively stimulated reservoirs in wells treated with multi-stage hydraulic fracture treatments:

1. Run Memory production logs on wells suspected of having zones unstimulated or ineffectively stimulated.
2. Evaluate production log and compare to the openhole logs. Estimate porosity-thickness product for each zone
3. Select underperforming intervals.
4. Isolate interval and perform an injection/falloff test to determine if a fracture exists.
5. History match data with simulator to estimate permeability-thickness product, reservoir pressure, skin factor or fracture width and fracture length.
6. Forecast production using simulator results.
7. Restimulate zones that can be economically justified.
8. Production test restimulated interval(s).
9. Analyze results.

Even when nitrogen treatments are used, procedures such as swabbing or soaping and then blowing the well should be performed during a well's life to remove any fluids above the Lower Devonian Shale perforations.

Additional studies should be performed to develop quicker, lower cost and more efficient methods to evaluate the effectiveness of stimulation.

## 5 Discussion Of Results

### 5.1 Literature Search

A literature search was performed to determine what if any studies were done on this subject. Searches were performed on selected terms: multistage fracturing, nitrogen fracturing, field testing, restimulation, testing. Two hundred sixty  $\pm$  abstracts, reports, or papers were reviewed. Seventy-seven of the more relevant abstracts, reports, or papers are listed in Appendix A. Twelve of the records had some bearing on this study.<sup>1,2,3,4,5,6,7,8,9,10,11,12</sup> The literature search confirmed that no previous study had been done for the specific purpose of this report.

### 5.2 Process procedure

To determine if a zone has been stimulated effectively we evaluated the following:

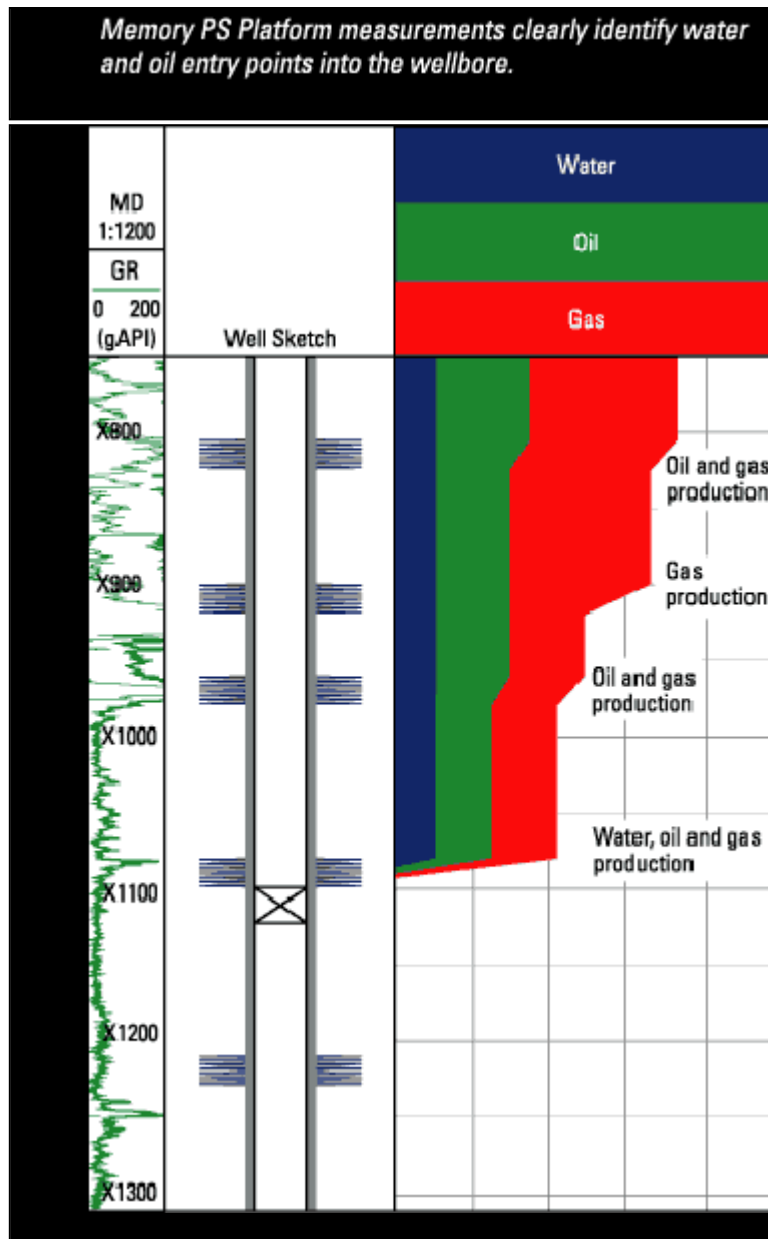
1. Memory production log to determine what zones are actually producing and their rates.
2. Openhole logs to determine which zones should have been productive if stimulated based on typical evaluation of net pay, porosity, and hydrocarbon saturations.
3. Predicted hydraulic fracture geometry that is depended on treatment.
4. Simulation of injection/falloff test to determine if an actual injection/falloff test would indicate if a zone had been effectively stimulated or not.
5. Actual injection/falloff test

Memory production logs (MPL) were run to determine the zones that were producing and their approximate production rates. Openhole logs were evaluated and compared to the MPL. To determine if a fracture had been created an injection/falloff test would be performed. To evaluate this injection/falloff test, the relative fracture geometry would need to be known. Since the majority of the zones were completed using nitrogen fracture stimulation, it was necessary to model this type of treatment to determine theoretical fracture width and length. Then a simulation of a nitrogen injection/falloff test was performed using the width and length estimated in the fracture modeling. Finally an actual injection/falloff test was performed and analyzed in a field test candidate.

### 5.3 Memory Production Logging

The use of memory production logs to determine the quantity of gas being produced from perforated intervals appears to perform fairly well. The MPL uses the same downhole tools and sensors to acquire measurements as a normal production log operation. To configure the MPL, the internal surface readout telemetry cartridge is simply replaced with a memory module and battery. The downhole tools are conveyed in the borehole by slickline. Cost savings is due to reduced manpower (one person can run the unit versus two to three for a normal electric line with surface readout operation) and the smaller unit is much less likely to need any additional equipment such as a dozer to get on location. This makes it a fast, easy, and safer operation.

The normal tool string configuration is a battery pack, memory production logging adaptor, casing collar locator, gamma ray, gradiomanometer, pressure recorder, temperature sensor, and a fullbore flow meter. The MPL can clearly identify gas, water and/or oil entry points into the wellbore **Fig. 3.**

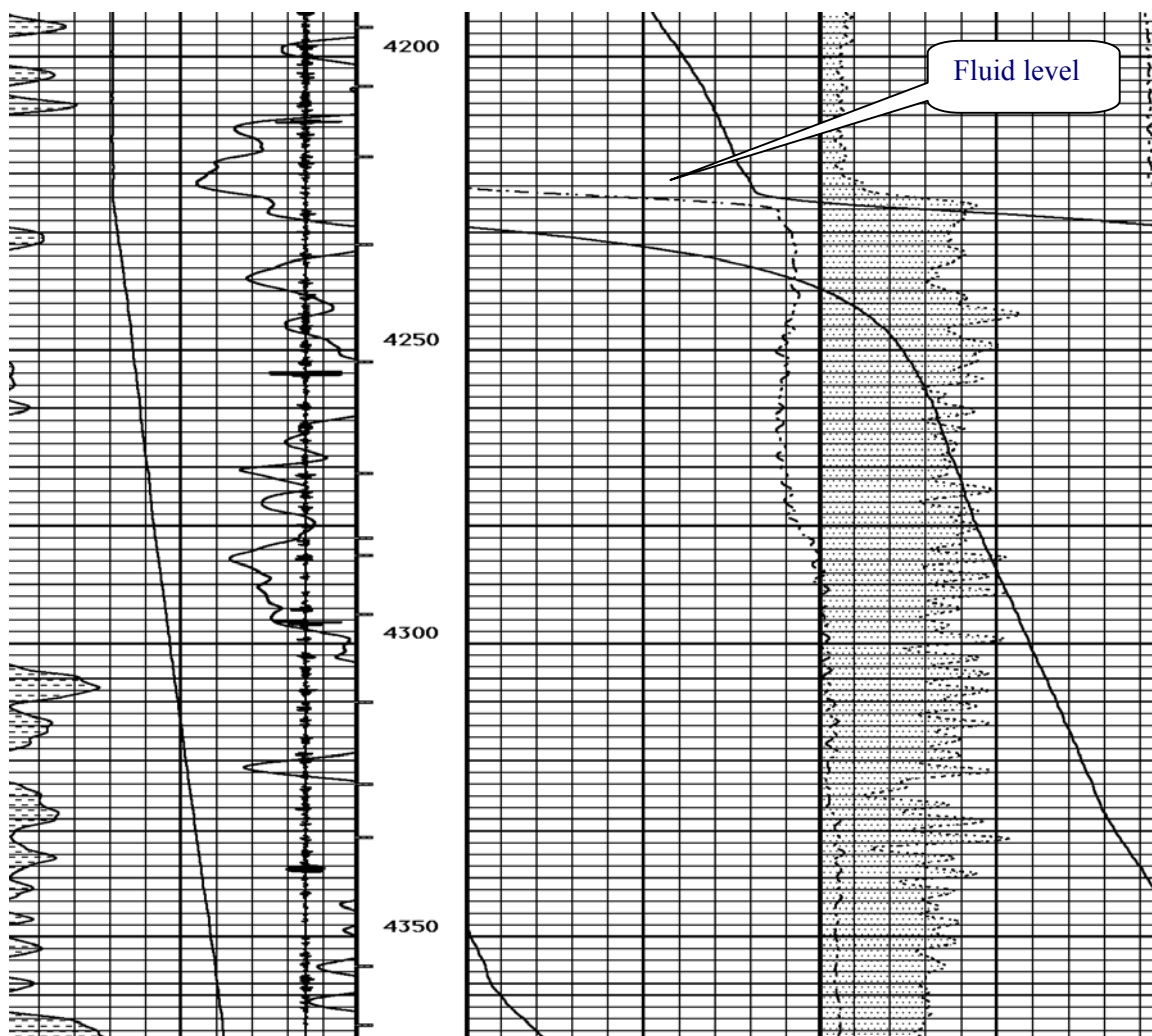


**Fig. 3 – MPL clearly identifies gas, water and/or oil entry into the wellbore.**

MPL's were run in 40 wells with 31 located in southern West Virginia and eastern Kentucky. Most wells were treated with 2 to 3 Nitrogen treatments. A typical treatment was performed using 600,000 to 800,000 scf of Nitrogen at rates of 60,000 to 80,000 scf/min. Usually a small amount of HCL acid (250 to 500 gallons) is pumped ahead of the nitrogen treatment to aid in the breakdown of the perforations. The biggest problem was most wells showed fluid levels in and even above the lower Devonian Shale perforated zones on the production log with the lower shale producing little if any in most of these wells. This was true even in the wells that the Berea and Devonian Shale were completed using only nitrogen fracture stimulation. Most of the wells had their fluid levels

shot and were subsequently swabbed less than two weeks prior to running the MPL. **The production-logging candidates are shown in the Appendix B.**

Of the 31 logs reviewed and correlated with openhole logs, it was determined that 10 of the wells had recompletion candidate zones. Ninety percent of the wells had fluid (mostly salt water with a few wells having small amounts of oil with the salt water) above the bottom perforation in the well **Fig. 4**. Forty percent had fluid covering the lowest completed formation. The formations that had potential for recompletion were the Big Lime, Berea, Weir, Upper Devonian Shale, and Lower Devonian Shale.

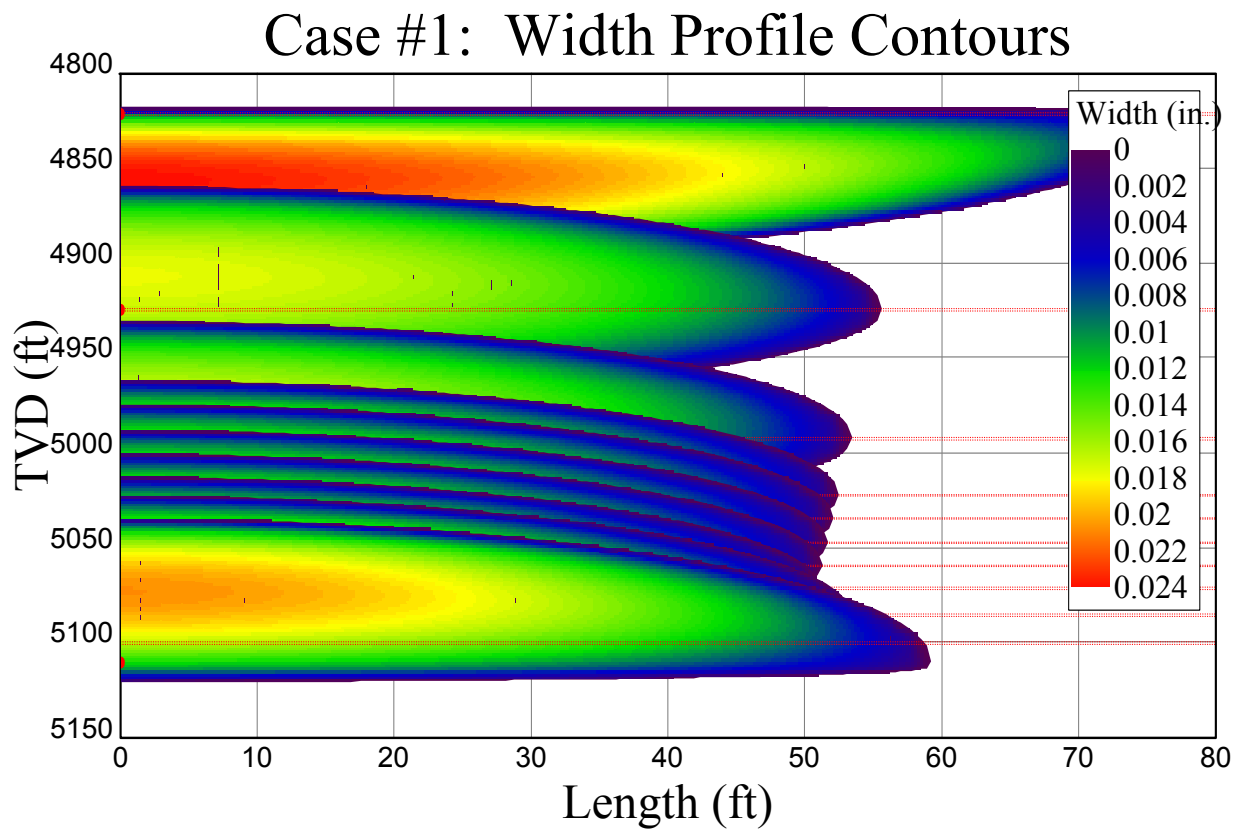


**Fig. 4 – MPL showing fluid level in Lower Devonian Shale.**

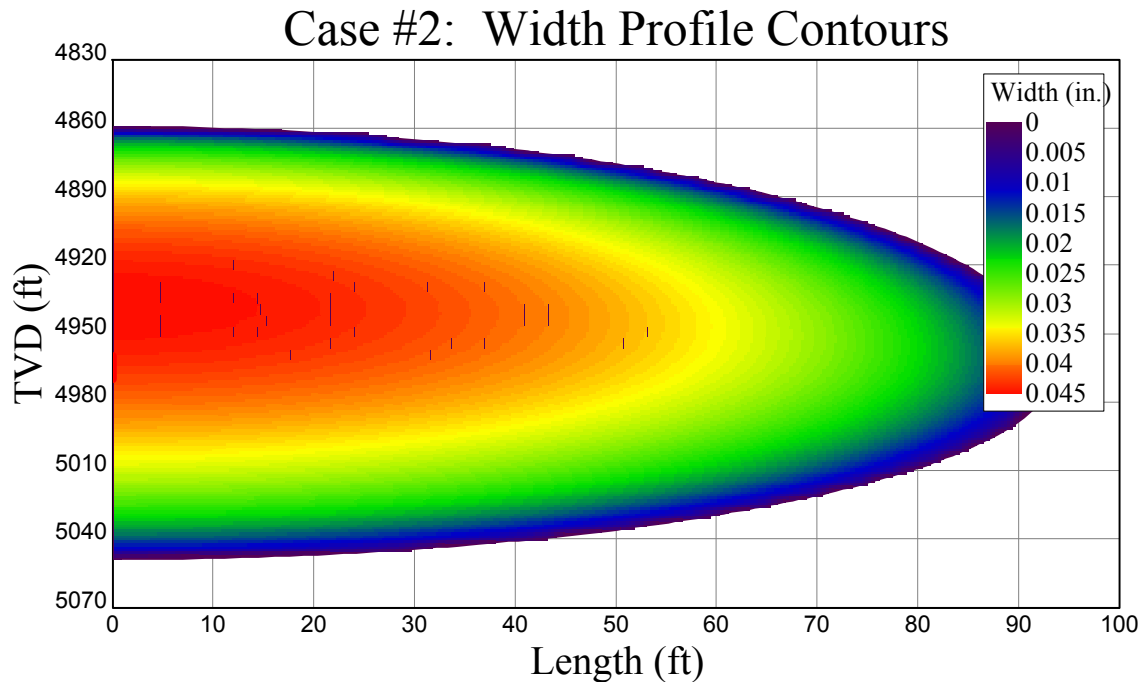
Equitable is in the process of running 33 additional memory production logs. They are running the logs based on the excellent information obtained in the original 31 MPL's. These logs will be evaluated to determine additional recompletion candidates.

## 5.4 Fracture Geometry

The Devonian Shale/Berea were typically completed by two-stage nitrogen fracture treatment in which each stage is perforated in four to ten intervals. To determine the theoretical fracture geometry for nitrogen fracture treatments two different models were designed using the Mfrac software. Both models assumed nitrogen fracture stimulations using 600,000 scf of nitrogen at treatment rates of 60,000 scf/min. The first model assumed that each interval (ten intervals were selected) was treated and each developed their own fracture. This model indicated frac widths of 0.013 – 0.015 inches with an average fracture length of approximately 55 ft, **Fig. 5**. The second model assumed all the intervals were treated, but only one fracture was formed. This model indicated a fracture width of 0.055 inches with a fracture length of approximately 95 ft, **Fig. 6**.



**Fig. 5 – Multiple fractures created.**



**Fig. 6 – One fracture created.**

While it would be very difficult to determine how many fractures are created during a treatment, it can be reasonably estimated that 2 to 3 fractures may be created, this depends on the existence of fracture barriers, number of perforations that break down, distance between perforations, nitrogen injection rate, deviation of the wellbore, angle of hydraulic fracture, etc.

## 5.5 Test Well

Ford Motor #165 was selected by DCS and EPC as a candidate for recompletion based on the production log and open hole logs. This well was completed in 1997 using a two-stage nitrogen fracture stimulation without proppant. The first stage was in the Lower Devonian Shale and the second stage was in the Upper Devonian Shale and Berea. The Lower Devonian Shale was perforated from 3,973 ft to 4,365 ft for a total of 24 holes. It was then nitrogen fracture stimulated using 600,000 scf nitrogen at a rate of 60,000 scf/min. 350 gallons of 8.2% HCL-Fe acid was dumped prior to the treatment to assist in breaking down the perforations. 27 perf balls were dropped during the treatment and slight ball action (pressure increases) was noted. The Upper Devonian Shale and Berea was perforated from 3,325 ft to 3,639 ft for a total of 23 holes. It was stimulated using 850,000 scf nitrogen at 60,000 scf/min. Four hundred gallons of 8.2% HCL-Fe acid were used. Twenty-six perf balls were dropped and good ball action was noted. The well was flowed back and had an openflow gas test of 592 Mscf/D.

The well had been producing since completion in 1997 and was producing 39 Mscf/D prior to running the MPL on April 2, 2001. The well was swabbed five days before the MPL with an initial fluid level at 4,050 ft. Almost the entire Lower Devonian Shale was covered with water. Six bbls of salt water were recovered during the swabbing. The production log indicated that the Upper Berea was not producing, **Fig. 7**. The openhole logs showed the zone to be 21 ft thick and have approximately 5% to 6% porosity and had indication of gas inflow on both the temperature and audio logs.

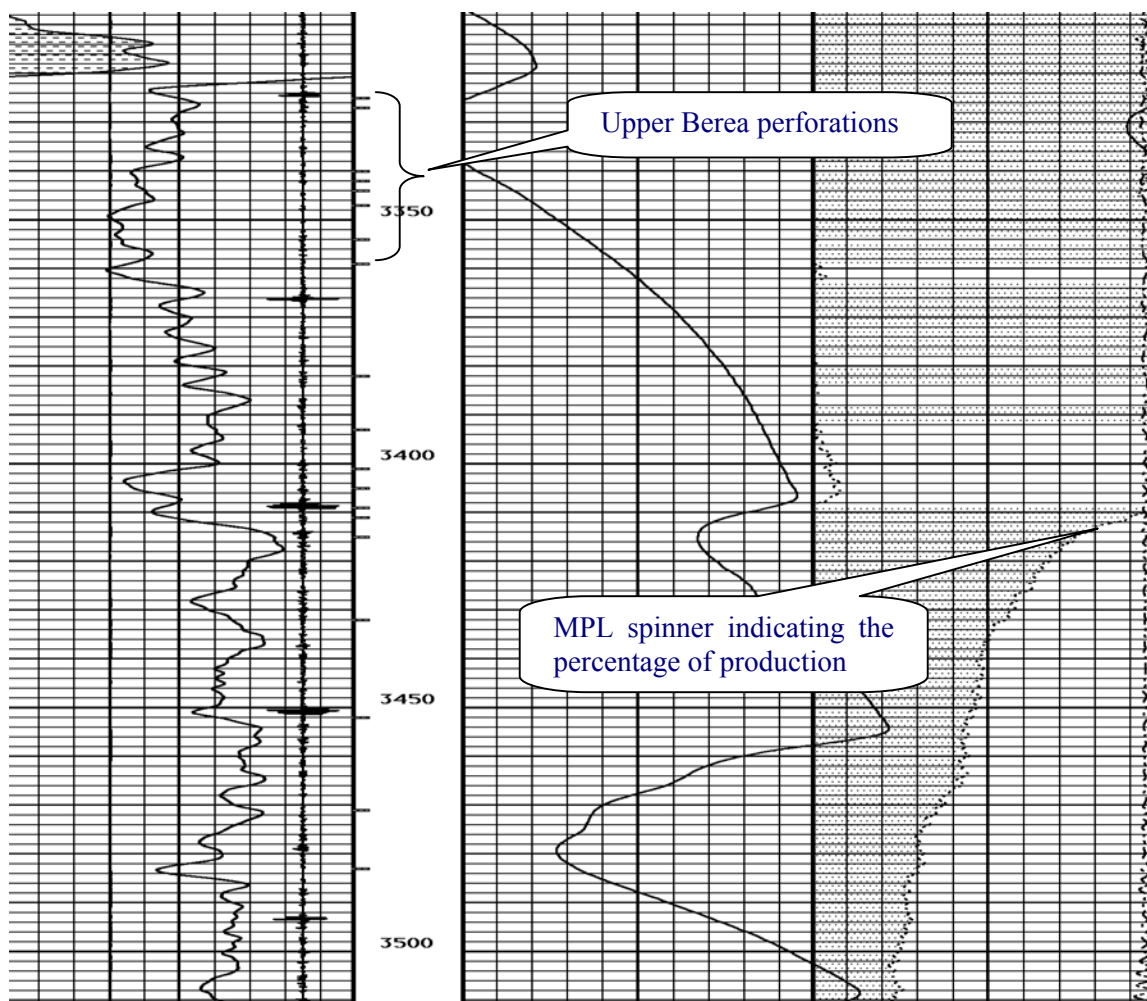
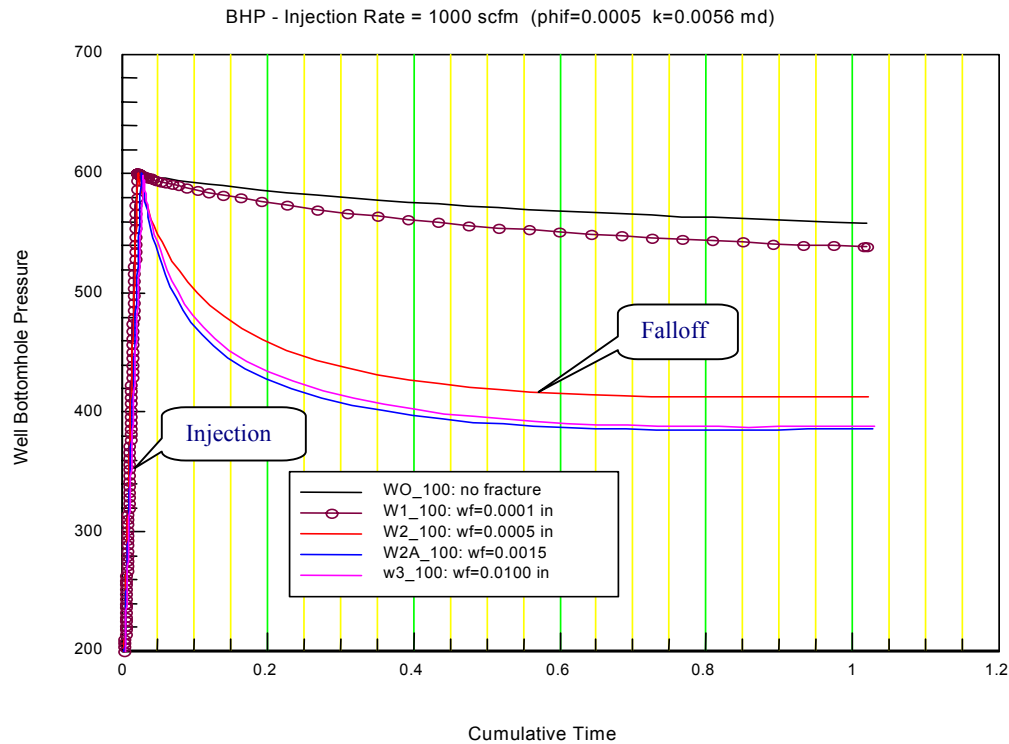


Fig. 7 – Ford Motor Company #165 MPL section through Berea.

## 5.6 Injection/Falloff Test Simulation

Part of our study involved a theoretical simulation evaluation to determine if a thin fracture created during a nitrogen stimulation treatment could be detected using an injection/falloff test using nitrogen. The simulation model using SHALEGAS<sup>TM</sup> was calibrated using the test well data. We assumed an openhole log porosity of 6%, net pay of 21 feet, an estimated original reservoir pressure of 745 psi and estimated reservoir permeability of 0.01 md. Sensitivities were run to simulate injection/falloff tests and gas production for various fracture aperture widths of no fracture (0 inches) up to widths of 0.005 inches. These simulation runs indicated that we would be able to determine if a fracture had been created if its width was at least 0.0003 inches, **Fig. 8**. The steep slope lines on the left side of the plot marked injection is the simulation of the injection phase of the test assuming a nitrogen injection rate of 1000 scf/min with fracture widths of 0 to 0.10 inches. The curved lines to the right of the injection phase are the simulated falloff pressure profile after injection ceases based on the fracture widths stated above. As shown in **Fig. 8** the falloff of the pressure should be much greater as the assumed fracture width (conductivity) is increased.

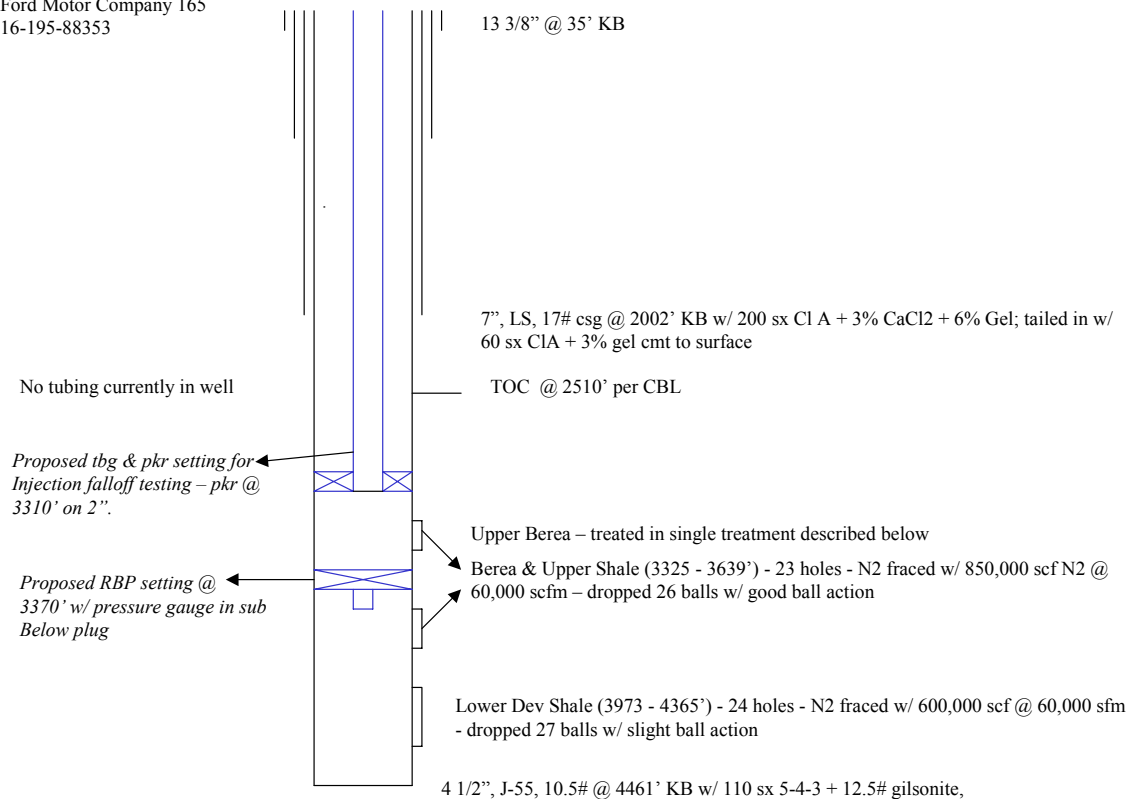


**Fig. 8 – Simulation of injection/falloff test in Upper Berea.**

## 5.7 Injection/Falloff Test

The testing of Ford Motor Company #165 well was initiated on July 17, 2002. Our plans called for performing an injection/falloff test with nitrogen to determine if a fracture existed in the Upper Berea. The well had been producing 30 Mscf/D into the pipeline from the Devonian Shale and Berea. The well was opened to the atmosphere and a gas test of 59 Mscf/D was taken. As stated above, the Upper Berea appeared not to be producing as per the memory production log ran on April 2, 2001. To perform the injection/falloff test and possible recompletion, tubing with a retrievable bridge plug and packer were run in the well to isolate the Upper Berea, **Fig. 9**. Once the bridge plug and packer were set, a gas test was taken with it being too small to measure. The well was put back in line overnight. The meter indicated that there was zero gas flow from the Upper Berea. The well was then shut in over the weekend.

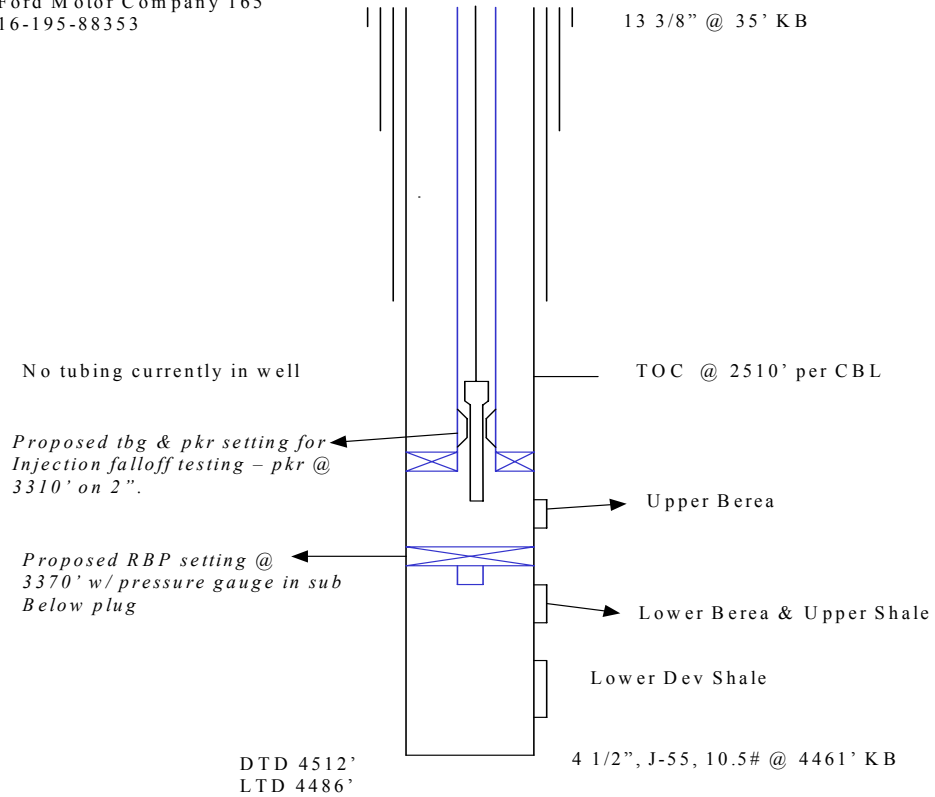
Ford Motor Company 165  
16-195-88353



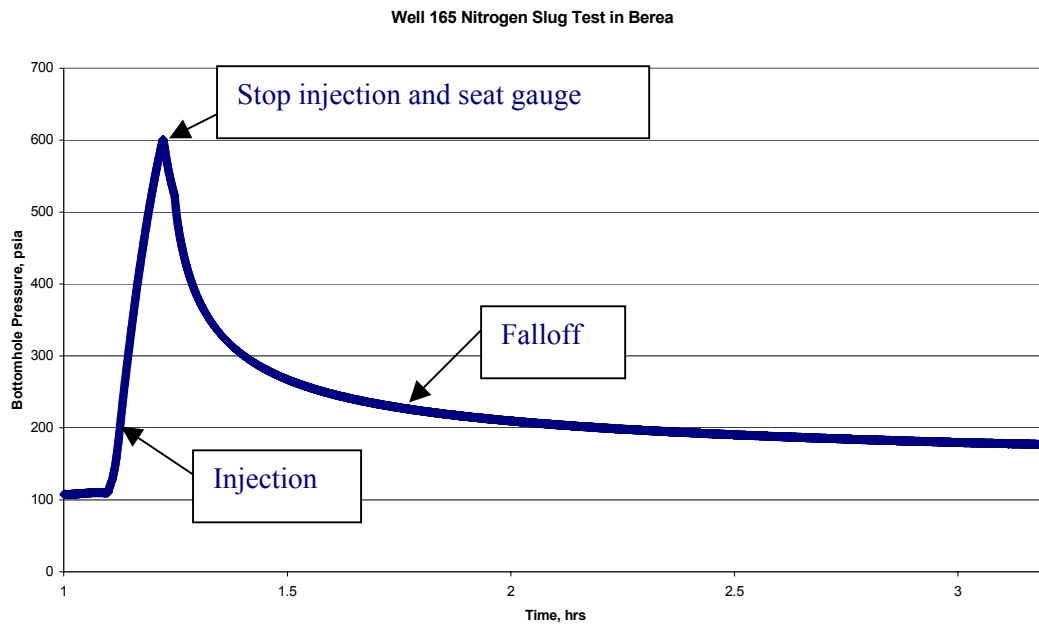
**Fig. 9 – Ford Motor Company #165 prepared for injection/falloff test.**

After the approximate 2 1/2 days of shutin, the well had a surface pressure of 80 psi. A pressure gauge on slick line was run in the tubing just above a seating nipple as shown in **Fig. 10**. An injection test was performed by pumping 6,500 scf of nitrogen at an average rate of 970 scf/D. Final injection pressure at the surface was 549 psi. The pressure gauge was lowered into the seating nipple to isolate the Upper Berea to record the pressure falloff. Pressure was increased to 769 psi on top of the pressure gauge to maintain a seal at the seating nipple. Bottomhole pressures were recorded during both the injection and falloff tests as shown in **Fig. 11**.

Ford Motor Company 165  
16-195-88353



**Fig. 10 – Ford Motor Company #165 well schematic during injection/falloff test.**



**Fig. 11 – FMC #165 injection/falloff test bottomhole pressure.**

Even though the injection/falloff data indicated a fracture and low reservoir pressure it was decided to restimulate the Upper Berea. The restimulation was performed by pumping 289 Mscf of nitrogen at an average rate of 20 Mscf/min rate. Gas test after cleanup was 47 Mscf/D. The well was put back in line and the Upper Berea produced at gas rates of 19 Mscf/D and 8.4 Mscf/D after one and two days, respectively. The tubing, packer, and bridge plug were pulled from the well. The well was put back in line and after 30 days it appears that the Upper Berea was producing an incremental 6 Mscf/D.

## 5.8 History Match of Injection/Falloff Test and Production Data

A history match of the pressure data from the injection/falloff test and of the production data after the restimulation was performed using SHALEGAS™. SHALEGAS is a versatile three-dimensional, two-phase, dual-porosity reservoir simulator designed to model flow of gas only, or gas and water in fractured shales such as the New Albany Shales of the Illinois Basin and Antrim Shale of the Michigan Basin, as well as other unconventional gas reservoirs. This includes formations such as the Berea, which is considered an unconventional reservoir due to low permeability and natural fractures. SHALEGAS numerically models the processes that control the behavior of these complex natural gas reservoirs: Darcy flow and desorption of gas in the matrix (in a shale) and Darcy flow of gas and water in the natural fractures. SHALEGAS was designed to predict the performance of these reservoirs. It can be used to design and analyze injection/falloff tests and history match reservoir performance.

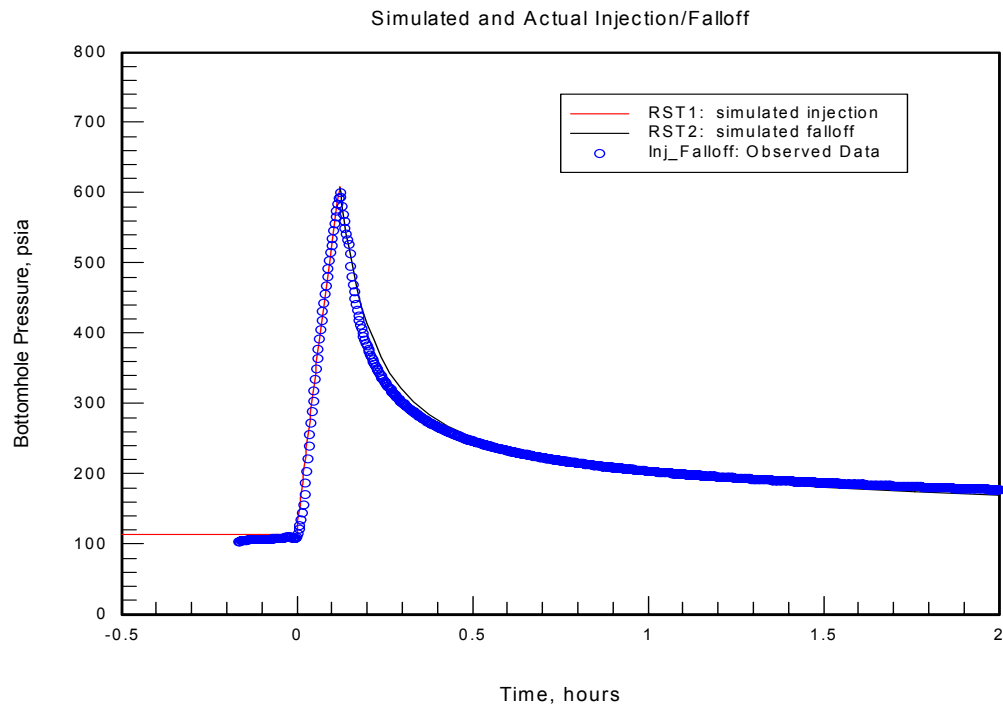
The Upper Berea is probably a dual-porosity reservoir based on other prior research in Pike County, Kentucky<sup>12</sup>. The primary porosity is a low permeability matrix. Gas is stored in the matrix porosity. The secondary porosity system in the Berea consists of one or more sets of natural fractures. These fractures are responsible for the majority of the flow capacity, but only a very small part of the total pore volume.

The most crucial part of any history match study is the reservoir description. The description includes an assumed size and shape of the reservoir, which is used to design the simulation grid. Other data, which must be specified as input data to the simulator, are porosity and permeability of the matrix and natural fractures, number of orthogonal fracture sets, and fracture spacing. SHALEGAS allows these properties to be varied throughout the grid system.

The best history match of the injection/falloff test in the Upper Berea in the Ford Motor Company #165 well (**Fig. 12**) includes the following:

- Reservoir pressure of 190 psi
- 21 feet of net pay
- Porosity of 5.4%
- Permeability of 0.05 md
- Fracture width of 0.000765 inches during injection
- Fracture width of 0.00045 inches during the falloff
- Hydraulic fracture length of 100 feet
- Conductivity of 0.4 md-ft.

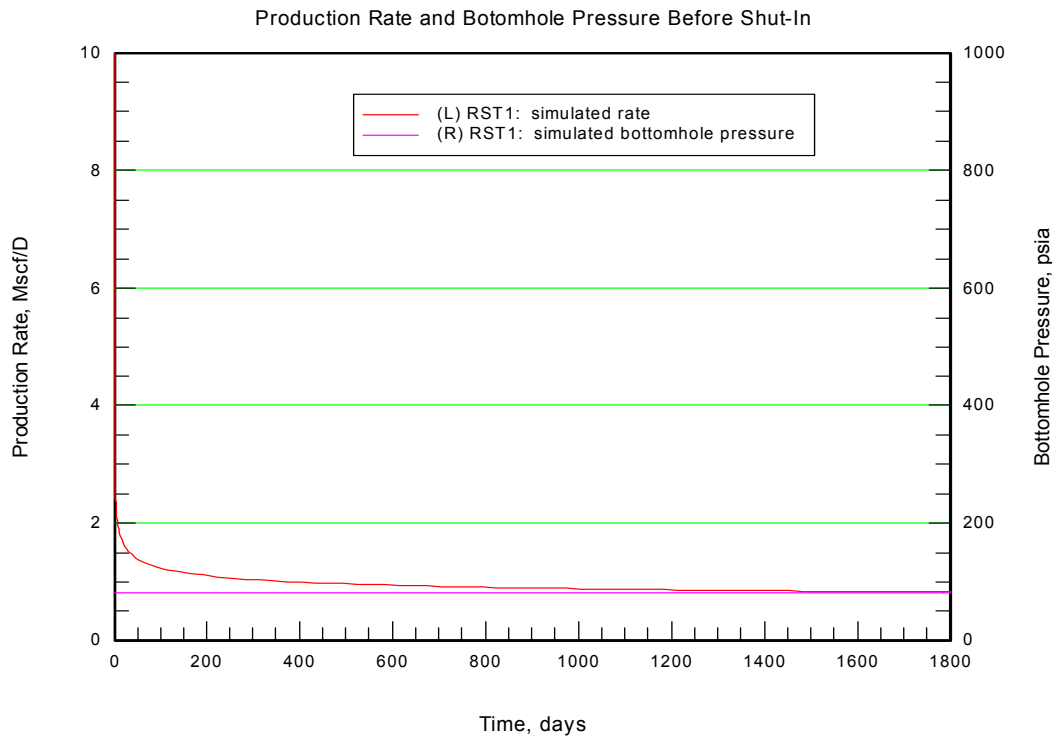
We did not use a dual porosity model because of the lack of information on the natural fracture system. A single porosity model adequately reproduces the pressure and rate history.



**Fig. 12 – History match of injection/falloff test.**

The above data from the history match of the injection/falloff test was used to history match the past production for the Upper Berea. As stated above the gas flow test of the Upper Berea after it was isolated was too small to measure. The production simulation using the history match data indicates the zone would currently be producing a rate of less than 1 Mscf/D as shown in **Fig. 13**.

EPC expected the reservoir pressure for the Upper Berea to be approximately 300 psi or the typical pressure found in wells that have also produced a few years. Since the Upper Berea was found to be nearly unproductive it could be expected to find reservoir pressure close to the original pressure of approximately 700 psi. A quick review of surrounding wells show there are three wells within 2000 feet of Ford Motor Co. #165 that each had produced more than 200,000 Mscf. It is possible that these three wells have depleted the pressure in the Upper Berea, especially in any possible existing fracture network. Since the history match of the injection/falloff test indicates a very narrow fracture, this is most likely a natural fracture and could be part of a fracture network.



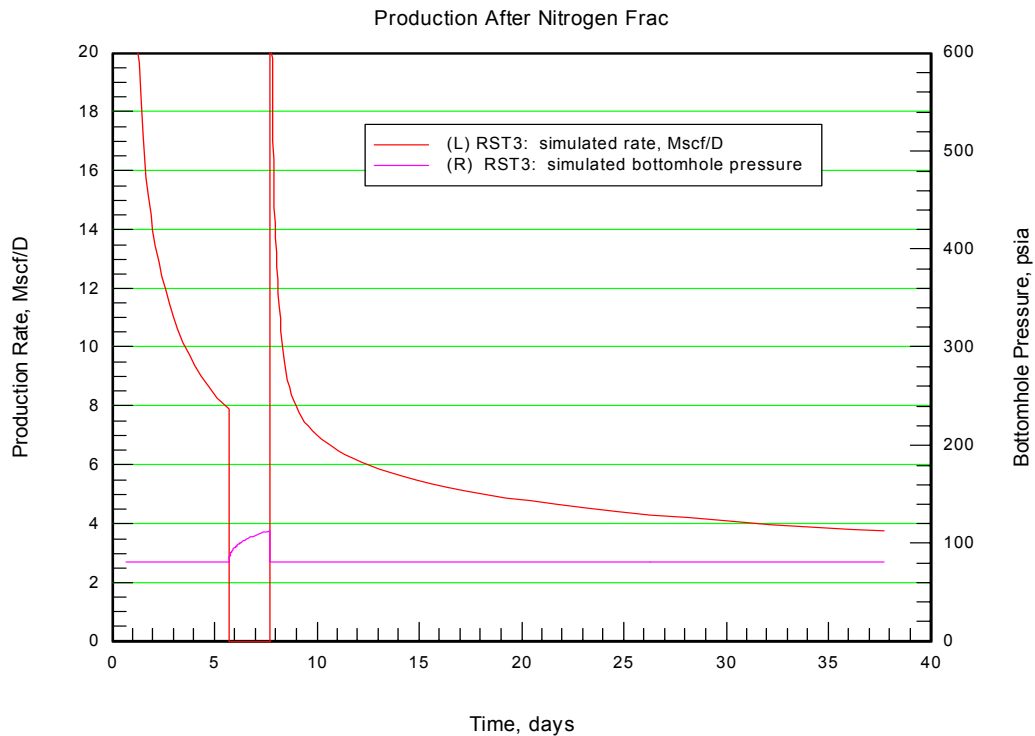
**Fig.13 – History match of Upper Berea production.**

## 5.9 Re-Stimulation of the Upper Berea

EPC decided to restimulate the Upper Berea using a nitrogen fracture stimulation. 289 Mscf of nitrogen at an approximate rate of 20,000 scf/min was used. The well was flowed back on a  $\frac{3}{4}$  inch overnight. Gas test the next morning was 47 Mscf/D. The well was put back in-line. The well produced 19 Mscf the first day and 8 Mscf the second day. The well was shut in for two days and had a shut in pressure of 120 psig. The tubing and packer were pulled and the bridge plug was retrieved. The well was put back on production. The Upper Berea was estimated to be producing 6 Mscf/D after 30 days of production.

A best fit history match of the production and pressure buildup after the nitrogen restimulation was performed **Fig. 14**. The results are as follows:

- Fracture half length of 100 feet
- Fracture width of 0.00605 inches
- Fracture conductivity of 1,000 md-ft



**Fig. 14 – History Match of Upper Berea After Restimulation**

The history match indicated that the restimulation probably created a wider fracture with the same initial length. This slightly improved performance. It is uncertain how long this fracture will remain open or what width it may retain due to the lack of proppant.

This well was a poor restimulation candidate due to the low reservoir pressure (190 psi) and the existence of a fracture (100 feet length and .00045 inches wide). The restimulation did increase the width of the fracture from 0.00045 to 0.00605 inches, but did not increase the length of the fracture. The well production improved from too small to measure to 6 Mscf/D, but the production will continue to decline and the zone has an estimated recovery of 14 MMscf. At an approximate cost of \$30,000 this restimulation was uneconomic.

While the result of FMC #165 was uneconomic, this was due mainly to the low current reservoir pressure. If the reservoir had a more normal reservoir pressure of 500 psi, the well would have had production rates more than 5 times higher and an estimated recovery of 65 MMscf. The restimulation would have been easily economic. It is important that a reasonable estimate of reservoir pressure be known prior to a restimulation to determine the economics. The minimum requirement for economic recompletion would be approximately 10 Mscf/D initial production rate or a reduction of cost below \$20,000.

Future research and development should attempt to find quicker and cheaper methods to determine if zones have been stimulated effectively. This could include methods to perform very short-term pressure buildup tests which would assist in determination of current reservoir pressure.

## APPENDIX A

1. Frantz Jr., J. H., Gatens III, J. M., Hopkins, C. W., and Lancaster, D. E.: "Analysis of Post-Fracture Diagnostic Experiments Performed on the Sterling Drilling and Production Jarvis 1143 Well (CSW 2), Calhoun Co., WY," GRI Topical Well Report 91/0241, GRI Contract No. 5086-213-1446, Nov. 1991.
  2. Hopkins, C. W., Frantz Jr., J. H., Hill, D. G., and Zamora, F.: "Estimating Fracture Geometry in the Naturally Fractured Antrim Shale," paper SPE 30483 presented at the 1995 Annual Technical Conference & Exhibition, Dallas, TX, Oct. 22-25.
  3. Hopkins, C. W., Jochen, J. E., and Fink, K. J.: "Comparison of Two Devonian Shale Wells: Why is One Better Than the Other?" SPE 26918 presented at the 1993 SPE Eastern Regional Meeting, Pittsburgh, PA, Nov. 2-4.
  4. Reeves, S. R., *et al.*: "Restimulation of Tight Gas Sand Wells in the Rocky Mountain Region," paper SPE 55627 presented at the 1999 SPE Rocky Mountain Regional Meeting, Gillette, WY, May 15-18.
  5. Hopkins, C. W. *et al.*: "Screening Restimulation Candidates in the Antrim Shale," paper SPE 29172 presented at the 1994 SPE Eastern Regional Conference & Exhibition, Charleston, WV, November 8-10.
  6. Kuuskraa, V. A. *et al.*: "Economic and Technical Rationale for Remediating Inefficiently Producing Eastern Gas Shale and Coalbed Methane Wells," paper SPE 26894 presented at the 1993 SPE Eastern Regional Conference & Exhibition, Pittsburgh, PA, November 2-4.
  7. Frantz, Jr., J. H., *et al.*: "Novel Well Testing Procedures Prove Successful in Dakota Formation Infill Program, San Juan Basin," paper 71519 presented at the 2001 SPE Annual Technical Conference and Exhibition, New Orleans, LA, September 30-October 3.
  8. Reeves, S. and Wolhart S.: "Study looks at Tight Gas Restimulation Candidate Wells," *Oil & Gas Journal* (October 8, 2001) 37-41.
  9. Spady, D. W. *et al.*: "Enhancing Production in Multi-Zone Wells Utilizing Fracturing Through Coiled Tubing," paper SPE 57435 presented at the 1999 SPE Eastern Regional Meeting, Charleston, WV, October 21-22.
  10. Reeves, S. R. *et al.*: "Benchmarks of Restimulation Candidate Selection Techniques in Layered, Tight Gas Sand Formation Using Reservoir Simulation," paper SPE 63096 presented at the 2000 SPE Annual Technical Conference and Exhibition, Dallas, TX, October 1-4.
  11. Mohaghegh, Shahab, *et al.*: "Development of an Intelligent Systems Approval for Restimulation Candidate Selection," paper SPE 59767 presented at the 2000 SPE/CERI Gas Technology Symposium, Calgary, Alberta, Canada, April 3-5.
  12. Frantz, Jr. J. H. *et al.*: "Research Results from the Ashland Exploration, Inc. Ford Motor Company 80 (COOP 2) Well, Pike County, Kentucky," S. A. Holditch & Associates, Inc. Topical Report to the Gas Research Institute, GRI-94/0258.1, GRI Contract No. 5086-213-1446, April 1993.
  13. Cipolla, C. L., and Wright, C. A.: "State-of-the-Art in Hydraulic Fracture Diagnostics" paper SPE 64434 presented at the 2000 Asia Pacific Oil & Gas Conference, Brisbane, Australia, October 16-18.
  14. Lakatos, I., *et al.*: "Polymer/Silicate Well Treatment Techniques: State-of-Art Experiences at the Algyo Field, Hungary" *Erdoel Erdgas Kohle* V 116, No. 4 (April 2000) 186-191.
-

15. Xu, F.: "Large Scale Acidizing Analyses for Gao Liu No. 1 Horizontal Well," Oil Drilling Production Technology V 19, No. 4 (August 20, 1997) 92-94, 99, 110.
  16. Gareishina, A. Z., *et al.*: "Biotechnological Method for Enhanced Oil Recovery by Reservoir Synthesis of Oil-Displacing Agents for High-Watered Oil Fields" presented at the 1995 EAPG Improve Oil Recovery Europe Symposium, Vienna Austria, May 15-17.
  17. Callahan, T., *et al.*: "Damage Removal Techniques Prove Successful in Horizontal Completions," presented at the 1995 CADE/CAODC Spring Drilling Conference, Calgary, Canada, April 19-21.
  18. Buciak, J. M., *et al.*: "Enhanced Oil Recovery by Means of Microorganisms: Pilot Test," paper SPE 27031 presented at the 1994 Latin American & Caribbean Petroleum Engineering Conference, Buenos Aires, April 26-29.
  19. Hernandez, J. M., *et al.*: "Methanol as Fracture Fluid in Gas Wells," paper SPE 27007 presented at the 1994 Latin American & Caribbean Petroleum Engineering Conference, Buenos Aires, April 26-29.
  20. Moses, V.: *et al.*: "Microbial Hydraulic Acid Fracturing," U.S. DOE Conference, Upton, New York, 1992.
  21. Boone, T., *et al.*: "Exploiting Fracturing Through High-Rate Injection in Cyclic Steam Stimulation," 1993 Heavy Oil & Oil Sands Technology Symposium, Calgary, March 9.
  22. Shelley, R. F.: "Artificial Neural Networks," *JPT* (February 2000) 42-45.
  23. Reeves, S., *et al.*: "A Systematic Way to Identify Restimulation Candidates in Tight Gas Fields," *GasTips* (Summer 1999), 21-30.
  24. Reeves, S. R., *et al.*: "Restimulation of Tight Gas Sand Wells in the Rocky Mountain Region," paper SPE 55627 presented at the 1999 Rocky Mountain Regional Meeting, Gillette, WY, May 15-18.
  25. Shelley, R. F.: "Artificial Neural Networks Identify Restimulation Candidates in the Red Oak Field," paper SPE 52190 presented at the 1999 Mid-Continent Symposium, March 28-31.
  26. Frantz, J. H., *et al.*: "Antrim Shale Development Technology Project" S. A. Holditch & Associates, Inc. Final Report to the Gas Research Institute, GRI-96-0389, November 1996.
  27. Reeves, S. R.: "Assessment of Technology Barriers and Potential Benefits of Restimulation Research and Development for Natural Gas Wells," Advanced Resources International, Inc. Final Report to the Gas Research Institute, GRI-96-0267, July 1996.
  28. Hopkins, C.: "Identifying Restimulation Candidates in the Antrim Shale," S. A. Holditch & Associates, Inc. Report to Gas Research Institute, GRI-94/0480, 1994.
  29. Young, G. B. C., *et al.*: "Reservoir Characterization of Mary Lee and Black Creek Coals at the Rock Creek Field Laboratory, Black Warrior Basin," Advanced Resources International, Inc. Topical Report to the Gas Research Institute, GRI-93/0179, August 1993.
  30. Young, G. B. C., *et al.*: "Characterization of Coalbed Reservoirs at the Rock Creek Project Site, Alabama," presented at the 1993 University of Alabama International Coalbed Methane Symposium, May 17-19, 705-714.
-

31. Aud, W. W.: "Acid Fracturing Program Increases Reserves, Cottonwood Creek Unit, Washakie County, Wyoming," paper SPE 21821 presented at the 1991 Rocky Mountain Regional Low Permeability Reservoirs Symposium, April 15-17.
  32. Ely, J. W.: "GRI's Restimulation Program Enhances Recoverable Reserves: Part 2: Case Histories of Restimulation Tests in Three Tight-Sand Areas," *World Oil* (December 2000), V 221, No. 12, 61-65.
  33. Ely, J. W.: "Program Finds Success in Enhancing Recoverable Reserve," paper SEP 63241 presented at the 2000 Annual SPE Technical Conference and Exhibition, Dallas, TX, Oct. 1-4.
  34. Ely, J. W.: "GRI's Restimulation Program Enhances Recoverable Reserves: Part 1," *World Oil* (December 2000), V 221, No. 11, 44-46, 48-50.
  35. Trentham, R. C. *et al.*: "Using Produced Water Analyses to Evaluate Production Problems and Recompletions in an "Old" Waterflood, Foster-South Cowden Fields, Ector County, Texas," presented at the 1999 West Texas Geological Society Fall Symposium, No. 99-106, October 28-29.
  36. McCoy, T. F.: *et al.*: "Depletion Performance of Poorly Stimulated Layered Reservoirs Without Crossflow," paper SPE 59757 presented at the 2000 SPE/CERI Gas Technology Symposium, Calgary, Alberta, Canada, April 3-5.
  37. Brister, B. S., *et al.*: "Waterfracs Prove Successful in Some Texas Basins," *Oil & Gas J.* (March 20, 2000) 74-76.
  38. Shelley, R. F.: "Artificial Neural Networks Identify Restimulation Candidates," *JPT* (February 2000), 42-45.
  39. Reeves, S.: "A Systematic Way to Identify Restimulation Candidates in Tight Gas Fields," *GasTips* (1999), 21-30.
  40. Mohaghegh, S., *et al.*: "Performance Drivers in Restimulation of Gas Storage Wells," paper SPE 57453 presented at the 1999 Eastern Regional Meeting, Charleston, WV, October 20-22.
  41. Jump, C. and Reeves, S.: "Integration for Restimulation," *Hart's Oil & Gas World* (July 1999) 32-33.
  42. Reeves, S. R., *et al.*: "Restimulation Technology for Tight Gas Sand Wells," paper SPE 56482 presented at the 1999 Annual Technical Conference & Exhibition, Houston, TX, October 3-6.
  43. Reeves, S. R., *et al.*: "Gas Storage Deliverability: Part 1: Novel Fracturing Enhances Deliverability," *Oil & Gas Journal* (November 15, 1999) 43-46.
  44. Hill, D. G., *et al.*: "Restimulation Research to Target Low-Cost, Incremental Gas Reserves," *GasTips* (Fall 1998) 30-39.
  45. Mohaghegh, S., *et al.*: "Candidate Selection for Stimulation of Gas Storage Wells Using Available Data with Neural Networks and Genetic Algorithms," paper SPE 51080 presented at the 1998 Eastern Regional Conference, Pittsburgh, PA, November 9-11.
  46. Wade, J. M., *et al.*: "Case History of Oil Well Performance Monitoring and Production Optimization in the Eldfisk and Ekofisk Fields, Norwegian North Sea," paper SPE 48847 presented at the 1998 Oil & Gas International Conference, Beijing, China, November 2-6.
-

47. Frantz, J. H. Jr., *et al.*: "Practical Production Data Analysis," paper SPE 39927 presented at the 1998 Rocky Mountain Regional Meeting, Denver, Colorado, April 5-8.
  48. Fairchild, N. R., *et al.*: "Optimization of a Restimulation Program in the Stark-Summit Gas-Storage Field," *JPT* (April 1998) 138-140.
  49. Fairchild, N. R., *et al.*: "Advanced Stimulation Technology Deployment Program, East Ohio Gas Company, Clinton Formation, Stark-Summit Storage Field, Ohio," GRI Topical Report 97/0125, January 1997.
  50. Frantz, J. H. Jr., *et al.*: "Antrim Shale Development Technology Project," S. A. Holditch & Associates, Inc. Final Report to the Gas Research Institute, GRI-96/0389, November 1996.
  51. Reeves, S. R.: "Assessment of Technology Barriers and Potential Benefits of Restimulation Research & Development for Natural Gas Wells," Final Report to Gas Research Institute, GRI-96/0267, July 1996.
  52. "Intensive Campaign in Venezuela," *Petroleum International*, (Sept/Oct 1996) 32-34-47.
  53. Frantz, J. H. Jr., *et al.*: "Practical Production Data Analysis for the Appalachian Basin," paper SPE 37347 presented at the 1996 Eastern Regional Meeting, Columbus, Ohio, October 23-25.
  54. Reeves, S. R., *et al.*: "Liquid CO<sub>2</sub> and Tip-Screenout Fracturing as Techniques for Restimulating Gas Storage Wells," paper SPE 37343 presented at the 1996 Eastern Regional Meeting, Columbus, Ohio, October 23-25.
  55. Frantz, J. H. Jr., *et al.*: "Evaluating Recompletion and Restimulation Potential in Antrim Shale Wells," paper SPE 35580 presented at the 1996 Gas Technology Symposium, Calgary, Canada, April 28-May 1.
  56. Kranker, S. A., *et al.*: "An Analysis of the Historical (Re)-Stimulation Results for 62 Dolomite Wells in the Texas Panhandle," paper SPE 35257 presented at the 1996 Mid-Continent Gas Symposium, Amarillo, Texas, April 28-30.
  57. Berumen, S.: "Evaluation of Fractured Wells in Pressure-Sensitive Formation," PhD Thesis, Oklahoma University, Oklahoma, OK (1995).
  58. Quinlan, W. C.: "Fracture Restimulation and Plunger Lift Applications within the Antrim Shale," presented at the GRI *et al.* Advances in Antrim Shale Technology Workshop, Mt. Pleasant, Michigan, December 13, 1994.
  59. Hopkins, C.: "Identifying Restimulation Candidates in the Antrim Shale," presented at the GRI *et al.* Advances in Antrim Shale Technology Workshop, Mt. Pleasant, Michigan, December 13, 1994.
  60. Hopkins, C. W., *et al.*: "Screening Restimulation Candidates in the Antrim Shale," paper SPE 29172 presented at the 1994 Eastern Regional Conference, Charleston, West Virginia, November 8-10.
  61. Fetkovich, M. J., *et al.*: "Useful Concepts for Decline Curve Forecasting, Reserve Estimation, and Analysis," paper SPE 28628 presented at the 1994 Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 25-28.
  62. "Strategies for Fundamental and Exploratory Research & Development in Natural Gas Extraction," U.S. DOE Report DOE/FE/61679-T4, 1993.
-

63. Hailey, R. G., *et al.*: "Case Study: Isolation and Restimulation of Granite Wash Zone in Mendota, NW Field Using Inflatable Packer Frac Liners," paper SPE 27933 presented at the 1994 Mid-Continent Gas Symposium, Amarillo, Texas, May 22-24.
  64. Young, G. B. C., *et al.*: "Reservoir Characterization of Mary Lee and Black Creek Coals at the Rock Creek Field Laboratory, Black Warrior Basin," Topical Report to the Gas Research Institute, GRI-93/0179, August 1993.
  65. Young, G. B. C., *et al.*: "Characterization of Coalbed Reservoirs at the Rock Creek Project Site, Alabama," 1993 Alabama University International Coalbed Methane Symposium, Birmingham, Alabama, May 17-21.
  66. Palmer, I. D., *et al.*: "Sandless Water Fracture Treatments in Warrior Basin Coalbeds," presented at the 1993 International Coalbed Methane Symposium, Birmingham, Alabama, May 17-21.
  67. Spafford, S. D., *et al.*: "Remedial Stimulation of Coalbed Methane Wells: A Case Study of Rock Creek Wells," presented at the 1993 International Coalbed Methane Symposium, Birmingham, Alabama, May 17-21.
  68. Friend, M. S., *et al.*: "A Pilot Program for Deliverability Maintenance," paper SPE 26902 presented at the 1993 Eastern Regional Meeting, Pittsburgh, Pennsylvania, November 2-4.
  69. Reeves, S. R., *et al.*: "Field Projects in the Antrim Shale: The Bagley East Project," Advanced Resources International, Inc. Report to the Gas Research Institute, GRI-92/04191, March 1993.
  70. Schraufnagel, R. A., *et al.*: "Restimulation Techniques to Improve Fracture Geometry and Overcome Damage," paper SPE 26198 presented at the 1993 Gas Technology Symposium, Calgary, Canada, June 28-30.
  71. Reeves, S. R., *et al.*: "Improved Production Practices for the Antrim Shale," *Gas Shales Technology Review*, (December 1992) 11-19.
  72. Dobscha, F. X., *et al.*: "Rock Creek Methane from Multiple Coal Seam Completion Project Annual Report," Taurus Exploration, Inc. Report to the Gas Research Institute, GRI-92/0257, August 1992.
  73. Reeves, S. R. *et al.*: "Pumps, Refracturing Hike Production from Tight Shale Gas Wells," *Oil & Gas J.* (February 1, 1993), 35-38.
  74. Hopkins, C. W. *et al.*: "Reservoir Engineering and Treatment Design Technology – Eastern States Exploration Company, Black Moshannon Field, Centre County, PA: Topical Well Report (April 1989-June 1990)," to Gas Research Institute, GRI-91/0016, January 1991.
  75. McGowen, H. E., III, *et al.*: "Development and Application of an Integrated Petroleum Engineering and Geologic Information System in the Giddings Austin Chalk Field," paper SPE 24441 presented at the 1992 Petroleum Computer Conference, Houston, Texas, July 19-22.
  76. Pike, W. J.: "New System Speeds Multiple Zone Horizontal Completions," *Ocean Ind.* (March 1992) 42-44.
  77. Branch, G. A., *et al.*: "Refracture Stimulations in the Norge Marchand Unit: A Case Study," paper SPE 21642 presented at the 1991 Production Operations Symposium, Oklahoma City, Oklahoma, April 7-9
-

## **APPENDIX B**

### Production Logging candidates (4/20/01)

#	Wellname	API	Completion (-stages; / zones)	Tubing	Goal	Estimated Cost	Costs to Drilling AFE - Y/N	Activity	Fluid Level Shot (feet fluid above bottom perf)	Date of Swab	Amount of fluid found above bottom perf by rig	Total Fluid Recovered (bbls water/bbls oil)	Prod. Rate before swabbing (mcf)	WHP (psig)	Line pressure before swabbing (psig)	Prod. rate after swabbing (mcf/d)	Prod. Log date	Producing Rate while logging (meter - mcf/d)	Production on Log determined Rate (mcf/d)	Production on Log determined fluid level (ft)	Feet fluid over bottom perf (ft)	Rig TD/LTD (ft)	Total Cost \$\$ /dozer, trucking, rig, prod. log)	Producing Rate 30 days after swabbing (mcf/d)	Water / Oil Analysis Results (ppm Cl / deg API)	Contribution Percentage by Zone as determined by Prod. Log	Comments - drill out baffles, plugs, salt, scale, paraffin, etc.		
	Eastern Gas & Fuel 168	4703905312	LDS-UDS/G/B-MW-BL-Rav	Yes	DS & shallow zonal contribution for offset completion design	\$6,000	Y	POOH w/ tbg / swab	NA	2/12/2001	NA	0	32	69 csg / 54 tbg	27	238	19-Feb	135	158	4445	80	4537/4536		113		Ravenciff - 8%; Big Lime - 3%; Middle Weir - 69%; Gordon/Berea/Upper Shale - 15%; Lower Shale - 5%	Note: Header % was wrong. Leave SN depth the same.		
2	Eastern Gas & Fuel 186	4703905323	LDS-UDS/G/B-W/BL	No	DS & shallow zonal contribution for offset completion design (all N2 completion)	\$3,500	Y	swab	649	13-Feb	3100	22	74	42 csg	40	217									84		Upper Weir/Big Lime - 20%; Gordon/Berea - 15%; Upper Shale - 27%; Lower Shale - 38%	Run tbg. Set SN @ 5300'	
								swab		14-Feb	4600	36	142	48 csg	45	217													
								swab		15-Feb	4600	3.8	201	52 csg	47.5	180													
								swab		22-Feb	4100	17	147	47 csg	45	145	22-Feb	146	220	4928	481	5425/5426			110000				
3	Eastern Gas & Fuel 191	4703905330	LDS-UDS/G/B-W/BL/MAX	Yes	DS & shallow zonal contribution for offset completion design	\$6,000	Y	POOH w/ tbg	NA	13-Feb	NA	0	155	142 csg / 103 tbg	65	321	19-Feb	291	330	5197	250	5540/5501			184	91689	Lower Maxton - 30%; Big Lime - 2%; Weir - 28%; Gordon/Berea - 18%; Upper Shale - 4%; Lower Shale - 18%	Leave SN depth the same.	
								POOH w/ tbg/swab	NA	14-Feb	347	2.25	317	90 csg / 90 tbg	75	240													
								Swab	NA	15-Feb	NA	0.4	304	85 csg	75	149												Losing fluid to perfs while swabbing.	
4	Briar Mountain 23	4703905341	LDS-UDS/G/B-UW-BL-MAX	Yes	DS & shallow zonal contribution for offset completion design (originally strap tested)	\$6,000	Y	Blow down	NA	NA	NA	0	227	354 csg / 300 tbg	62.5	LOON	20-Feb	282	430	5594	638	6217/6220			256	91866	Middle Maxton - 48%; Lower Maxton - 2%; Big Lime - 10%; Upper Weir - 20%; Gordon/Berea/Upper Shale - 5%; Lower Shale - 15%	Blow down well - found pinched. On 3/17 - well flowing 258 mcf/d w/ 284# whp - fluid problems.	
								POOH w/ tbg/swab	NA	16-Feb	scattered	9	NA	60 csg	62.5	207												Leave SN depth the same.	
5	Siler 32	4700501521	LDS-UDS-BI-BL	Yes	DS & shallow zonal contribution for offset completion design	\$6,000	Y	POOH w/ tbg	NA	28-Feb															49	85000	Big Lime - 20%; Big Injun - 25%; Upper Devonian - 53%; Lower Devonian - 2%	Run single string 1 1/2. Set SN @ 3415'.	
								swab		27-Feb	None	0.33	47	20 csg	17.5	50	2-Mar	58	62	4325	0	4398/4351							
								swab		28-Feb	None	0	NA	NA	NA	NA													
6	Carbon Fuel 46	4703905348	LDS-UDS-G/B-LW-UW-BL	Yes	DS & shallow zonal contribution for offset completion design	\$6,000	Y	POOH w/ tbg	NA	15-Feb	NA	0	85	123 csg / 100 tbg	44	131	20-Feb	83	80	5300	460	5760/5772			67		Big Lime - 25%; Upper Weir - 15%; Lower Weir - 5%; Gordon/Berea - 25%; Upper Devonian - 25%; Lower Devonian - 5%	Note- header % was wrong.Set SN @ 4400'.	
								POOH w/ tbg/swab	NA	16-Feb	NA	5	114	50 csg / 50 tbg	43	97													
7	Pocahontas 42	4701900920	LDS-UDS/B-W/SQ/BI-BL	Yes	DS & shallow zonal contribution for offset completion design	\$6,000	Y	POOH w/ tbg	NA	19-Feb	NA	0	40	106 csg / 66 tbg	65	91									40	116000	Big Lime/Lower Maxton - 30%; Weir/Big Injun/Squaw - 55%; Berea/Upper Shale - 13%; Lower Shale - 2%	Recovered 2 rabbits from well on day 1. Set SN @ 4200'.	
								swab	NA	21-Feb	280	2.5	66	73 csg	68	66	26-Feb	70	92	5488	492	6000/6025							
8	Jefferey Manufacturing 10	4701900897	LDS-UDS-G/B-LW/UW-BI-BL-MAX	Yes	DS & shallow zonal contribution for offset completion design	\$6,000	Y	POOH w/ tbg	NA	19-Feb	NA	0	41	167 csg / tbg-shut in	58	79									43	143000	Maxton - 40%; Big Lime - 15%; Big Injun - 15%; Weir - 20%; Gordon/Berea - 5%; Upper Shale - 5%; Lower Shale - no contribution.	Well found feeding off casing.Set SN @ 3400'.	
								POOH w/ tbg/swab	3650	20-Feb	2642	18.5	100	68 csg	68	85												Losing approx. 75% of swab load to perfs.	
								swab	3900	21-Feb	2292	6.5	78	66 csg	65	47	22-Feb	68	118	3918	2374	6174/6100			706		LTD varies significantly from service rig TD because tools were left in the hole and loggers were instructed to stay off bottom.		
9	Eastern Gas & Fuel 152	4703905261	LUDS-G/B-W/BL/MAX	No	DS & shallow zonal contribution for offset completion design	\$6,000	Y	NA	NA	NA	NA	0.4	245*	36 csg	33	375									706		*Clean out sd 1514-32' - well kicked off - recover frac ball - flow to clean up - *Abandon exercise - no swabbing done - remove from production log candidate list.		
10	Wood 9	4700501712	LDS-UDS/B/BL	No	DS & shallow zonal contribution for offset completion design	\$6,000	Y	swab	813	22-Feb	499	8.5	55	28 csg	20	49	2-Mar	38	62	4890	58	5000/5059			37		Big Lime - 23%; Berea - 30%; Upper Shale - 44%; Lower Shale - 3%.	Fluid recovery est. 50% oil. Did not tag TD - just cleared bottom perf.	
2	Ritter 348	4710901945	G/B-BL-Rav	Yes	Zonal contribution with comparison of frac tracer survey	\$6,000	N	POOH w/ tbg	NA	9-Mar	NA	0	175	73 tbg 73 csg	33	NA									215	46021		Well dry - tubing will not be run back in after logging - salvage for use elsewhere. Large discrepancy between metered flow and log determined flow.	
								POOH w/ tbg swab	NA	12-Mar	0	0	194	30 csg	30	156	16-Mar	234	500	0	0	3800/3781					Ravenciff - 11%; Big Lime - 66%; Gordon/Berea - 23%		
3	Pocahontas/Camegie 2	4705901386	LDS-UDS-BL	No	DS-Rhinestreet contribution for offset development	\$3,500	Y	swab	NA	2-Mar	1255	20	88	25 csg	7	63	8-Mar	96	92	5110	45	5159/5164			99		Big Lime - 40%; Upper Shale - 20%; Lower Shale - 40%		
								swab	NA	5-Mar	NA	0.5	99	30 csg	9	NA												Well was shut in prior to production logging due to curtailment with CNG; well was vented for 1 hr to bring flowing pressure down to line pressure - may have brought fluid in during flow down.	
4	Pardee 93	4704501280	LDS-UDS-B/W-BL	No	DS & shallow zonal contribution for offset completion design	\$3,500	Y	swab	674	1-Mar	1134	28	54	90	32	NA	7-Mar	380	380	5904	787	6757/6748			94		Big Lime - 12%; Berea/Weir - 73%; Upper Shale - 10%; Lower Shale - 5% or less.	Prod. Rate after swabbing after 1 hr - still increasing.	
								swab	NA	2-Mar	0	0	110	89	38	89													
5	Hinchman B-2	4704501330	LDS-B/G-W/BL-MAX	Yes	DS & shallow zonal contribution for offset completion design	\$6,000	Y	swab	NA	5-Mar	1886	1.5	74	NA	15	NA	13-Mar	115	120	4911	430	5350/5425			105	66892	Middle Maxton - 20%; Weir/Big Lime - 35%; Gordon/Berea - 35%; Lower Shale - 10%		
								swab	NA	6-Mar	1341	17.5	82	43 csg	17	NA													
								swab	NA	7-Mar	NA	5	84	NA	15	NA													
6	Elk Creek 36	4705901308	LDS-UDS-B-BL	No	DS-siltstone & shallow zonal contribution for offset completion design	\$3,500	Y	KO Frac Plug & baffle	0	2-Mar	NA	0	96	95	95	NA	8-Mar	103	157	4928	512	5490/5408			121		Big Lime - 35%; Berea - 35%; Upper Shale - 20%; Lower Shale - 10%	Discrepancy between service rig TD & loggers TD (82'). KO'd frac plug, baffle and cleaned out to 5490'.	
								KO baffle & sd pmp	NA	3-Mar	NA	0	96	95	95	NA													
								Sd pmp & swab	NA	4-Mar	NA	16	93	95	95	NA													

7	Elk Creek 42	4704501367	LDS-UDS-B-BL	No	DS-siltstone & shallow zonal contribution for offset completion design	\$3,500	Y	swab		511	5-Mar 6-Mar	2685	12 12	103 144	NA 50 csg	24 20	NA	13-Mar	176	203	5478	407	5904/5736		158	Big Lime - 20%; Berea - 23%; Upper Shale - 37%; Lower Shale 20%	TD reached with PL tool was significantly shallower (268') than rig TD.
8	Ritter 235	4710901078	RAV-G-DS (can't find file)	Yes	DS-zonal contribution for offset completion design	\$9,000	Y	POOH w/ dual strings	NA		13-Mar	NA	0	11 deep 86 shallow	44 deep 40 shallow	40	NA	20-Mar	72	85	5872	270	6195/6159		73860	Ravenc Cliff - 80%; Lower Maxton - 0%; Gordon - 10%; Upper Shale - 0%; Lower Shale - 10%	Sand pumped 10' of fillup out of well 6185-6195'.
								POOH w/ dual strings / swab	NA		14-Mar	0	0	121 total	NA	50	NA										
9	Island Creek 'D' 86	4704501274	DS-BL	No	DS-Rhinestreet & shallow zonal contribution for offset completion design	\$3,500	Y	swab		82	26-Feb	623	10.3	284	80 csg	72.5	301								261		
								swab			27-Feb	NA	5	301	80 csg	72.5	NA	5-Mar	283	275	284	23	4414/4413			Weir/Big Lime - 85%; Upper Shale/Gordon/Berea - 12%; Lower Shale - 3%	
10	Island Creek 'D' 29	4704501156	LH-G-B	Yes	DS & shallow zonal contribution for offset completion design	\$9,000	Y	POOH w/ tbg	NA		27-Feb	NA	0	35	33	12	84.5	7-Mar	NA	155	4464	34	4527/4519		110	75680	Big Lime - 60%; Berea/Upper Shale - 10%; Lower Shale - 20%; Rhinestreet - 10%; Rerun single string of tubing; set SN @ 4400' - Rhinestreet is contributing 10% of flow. Need additional Well Info from D&C personnel.
								POOH w/ tbg/swab	NA		28-Feb	498	12	NA	NA	NA	NA										
								swab	NA		1-Mar	NA	0	NA	NA	14	NA										
11	Cole & Crane B26	4704501285	DS-B-BL	No	DS & shallow zonal contribution for offset completion design	\$3,500	Y	POOH w/ tbg		317	26-Feb	NA	0	NA	NA	NA	NA	5-Mar	48	66	4520	194	4750/4718		55	Big Lime - 20%; Berea/Sunbury Sh - 30%; Upper Shale - 47%; Lower Shale - 3%	
								swab			27-Feb	824	18	35	33 csg	12	NA										
								swab			28-Feb	0	0	84	NA	17	NA										
12	Thacker A-7	4705901273	DS-BL(can't find file)	No	DS-Rhinestreet & shallow zonal contribution for offset completion design	\$3,500	Y	swab		821	8-Mar	610	9	36	NA	5	72	15-Mar	75	80	5021	89	5120/5117		61	Big Lime - 20%; Weir/Berea - 0%; Upper Shale - 70%; Lower Shale - 10%	
								swab	NA		9-Mar	0	0	75	NA	5	91										
13	David Francis Trust 4*	4705901316	LDS-UDS-B	No	DS comparison - Rhinestreet	\$3,500	Y	swab		205	12-Mar	NA	6	NA	70	70	NA	16-Mar	74	80	4264	30	4339/4330		69	44475	Big Lime - 40%; Upper Shale - 52%; Lower Shale - 8% Found meter reading with a negative differential - contact Kinzer for repair. Follow-up with Kinzer for adjustments.
								swab			13-Mar	0	0	81	70	61	NA										
14	David Francis Trust 5*	4705901317	DS-B-BL	No	DS comparison - Rhinestreet	\$3,500	Y	swab		227	10-Mar	727	12	72	70	70	85	15-Mar	75	68	4076	51	4156/4151		71	55395	Big Lime - 20%; Berea - 20%; Lower Shale - 60%
15	Pardee Land 89	4700501612	BL/BE/DS/RH	Yes	Test area for new 2001 drilling (Rhinestreet contribution) - well makes 2 BW/mo	\$6,000																					
16	Southern Land 32	4700501683	MX/BL/WE/BE/DS	Yes	BI/WE/BE - N2 gas traced - 1 stage BI/WE/BE; also CO2 traced SH; 1 BW/mo	\$6,000																					
17	A.H. Cole B-16	4704501173	BL/BE/DS	Yes	Rhinestreet Contribution - Dual 1.9" strings of tubing	\$9,000																					
18	Pocahontas/Carnegie #1	4705901384	BL/BE/GD/DS/RH	No	Rhinestreet Contribution	\$4,000																					
19	Isand Creek D55	4705901169	BL/BE/GD/DS/RH	Yes	Rhinestreet Contribution - Dual 1.9" strings of tubing	\$9,000																					
20	Isand Creek D23	4705901149	BL/BE/GD/DS/RH	Yes	Rhinestreet Contribution - Dual 1.9" strings of tubing	\$9,000																					
								swab	NA		12-Mar	0	0	79	75	73	NA										
1	VP-4018		LDS-UDS-WE-BL	Yes	Evaluate zonal contribution - especially Weir for use on future wells.	\$6,000	Y	POOH w/ tbg / swab	NA		14-Mar	592	6					19-Mar	61	65	3868	122	dd/4067		95	Big Lime - 20%; Weir - 10%; Cleveland Shale - 50%; Lower Huron - 20%	
2	VP-4023		LDS-UDS-WE-BL	Yes	Evaluate zonal contribution - especially Weir for use on future wells.	\$6,000	Y											19-Mar	110	114	3428	216	dd/3720		93	Big Lime - 78%; Weir - 5%; Cleveland Shale - 14%; Lower Huron - 3%	
1	EPC (Anthony Frashure TR) 2 KF4128	Coffe-US-LS (2 stage)	No	Coffee Shale was completed - evaluate for contribution.	\$3,500	Y	Swab	NA			4/3/2001	-1'	1 wtr	132	47	47	NA	4/6/2001	192	70	3145	4'	3193 / 3208		32385	Berea/Upper Shale 55%, Lower Shale 45%	
2	KF1611		US-LS (2 stage)	No	Underperforming well - eval for zonal contribution. Identify problem zones.	\$3,500	N	Swab	NA		3/29/2001	-5'	.3 wtr	16	45	45	NA	4/3/2001	16	27	3484	46'	3558 / 3553		72420	Berea/Upper Shale 50%, Lower Shale 50%	
3	KL4390		BL-US-LS (3 stage)	No	Underperforming well - eval for zonal contribution. Identify problem zones. BL thief zone? Info important for offset development - BL or no BL?	\$3,500	Y	Swab	NA		3/29/2001	531'	10 wtr / 15 oil	4	7	7	NA	3/30/2001	27	38	1880	351'	2293 / 2292		34.1	Big Lime 10%, Berea/Upper Shale 10%, Lower Shale 80%	
4	6644 DD		US-LS (3 stage)	No	Eval zonal contribution for future wells.	\$3,500	Y	Swab	NA		3/29/2001	480'	.2 oil	19	30	30	NA	4/4/2001	19	23	2616	-1'	2650 / 2654		25	Berea/Upper Shale 10%, Lower Shale 90%	
5	Rouge Steel 2	1619586628	Be-US-LS	No	6 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swab		324' 12/5/00	3/28/2001	432'	4.8 wtr	118	36	36	NA	4/2/2001	68	89	5392	840	4288 / 4252		32988	Berea/Upper Shale 60%, Lower Shale 40%	
6	Ford Motor Co. 1-094	1619590712	BL-Clev-LowHur	No	2 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swab	NA		3/27/2001	526'	14.3 oil	156	42	42	NA	3/30/2001	184	190	4320	704'	5133 / 5118		35.8	Big Lime 10%, Berea/Upper Shale 80%, Lower Shale 10% May need tbg.	
7	Smith-Carrs Fork Unit #2-1	1611989884	BL-Clev-LowHur	No	4 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swab	NA		4/2/2001		3.25 wtr / 3.25 oil	37	45	45	NA	4/9/2001	67	82	3345	313'	3665 / 3678		58,574	Big Lime10%, Upper Shale/Berea 70%, Lower Shale 20%	

8	Hatcher 4-105	1607191663	BL-Clev-LowHur	Yes	3 offsets planned in 2001 - zonal contribution definition	\$6,000	Y	MIRU	NA	3/14/2001			48.3	25	25	NA	3/22/2001	55	57	3292	39	3450 / 3446	6393	62	40	Big Lime 0%, Upper Shale/Berea 50%, Lower Shale 50%	Tbg re-ran w/ SN at original depth.
								TOOH w/tbg; swb		3/15/2001	125'	6 oil															
9	Hatcher 4-060	1619590909	Bl/We-Clev-LowHur	No	1 offset planned in 2001 - zonal contribution definition	\$3,500	Y	Swb	NA	3/21/2001	600'	1.1 wtr / 9.6 oil	16	30	30	NA	3/26/2001	15	15	2704	490	3210 / 3209			35.5	Big Lime/Borden 30%, Berea/Upper Shale 65%, Lower Shale 5%	May need tbg.
10	Republic Steel 2-108	1619591756	Mx-BL-Clev-LowHur	No	4 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Dri FP Dri FP	NA	3/12/2001 3/13/2001		98.2	45	45	NA	3/22/2001	132	---	---	---	4150 / 4148	6244	119	53455	Due to large volume of fluid in hole, an accurate interpretation cannot be made. Substantial flow exists from MX & U DS 3300-3320'	Found dump valve stuck open prior to logging- loaded w/ gas cut fluid.	
								Swb		3/14/2001	2323'	32.1 wtr															Run tbg w/ SN @ 4020' - under original AFE.
11	Colony Coal & Coke 2-101R	1619590679	BL-Clev-LowHur	No	5 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swb	NA	3/22/2001	150'	5.3 wtr	86	77	77	NA	3/27/2001	114	130	5051	91	5189 / 5178			74551	Big Lime 10%, Berea/Upper Shale 50%, Lower Shale 40%	
12	EPC (Hall, WD) KF 4427	1611991010	We-Clev-LowHur	No	No offsets planned in 2001 - zonal contribution definition	\$3,500	N	Swab	NA	3/30/2001	104'	4.2	46	40	40	NA	4/4/2001	79	108	2843	169	3068 / 3084			58226	Borden/Weir 15%, Berea/Upper Shale 77%, Lower Shale 8%	
13	Chesapeake Min. 2-051	1619591303	BL-Clev-LowHur	No	2 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swb	NA	3/21/2001	250'	9.5 wtr	76	41	41	NA	3/27/2001	70	100	4253	239	4489 / 4537			86991	Big Lime 0%, Berea/Upper Shale 70%, Lower Shale 30%	
14	Emperor Coal 1-285	1619590986	BL-Clev-LowHur	No	2 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swab	70' 2-21-01	3/28/2001	70'	1.8 wtr	57	38	38	NA	4/2/2001	57	72	4400	70	4546 / 4529			50359	Big Lime 55%, Berea/Upper Shale 25%, Lower Shale 20%	
15	Ford Motor Co. A-165	1619588353	Be-Clev-LowHur	No	4 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swab	NA	3/28/2001	fl @ 4050'	6 wtr	39	40	40	NA	4/2/2001	39	40	4222	143	4396 / 4386			58658	Berea/Upper Shale 80%, Lower Shale 20%	
16	KF 4300 JJ Kendrick	1619591330	We-Clev-LowHur	No	No offsets planned in 2001 - zonal contribution definition	\$3,500	N	Swab	NA	4/3/2001	546'	10 oil	61	50	50	NA	4/6/2001	127	62	4245	67	4189 / 4216			50312	Weir 15%, Berea/Upper Shale 45%, Lower Shale 40%	
17	Solvay-Coleman 2-018	1619591342	Mx-BL-Clev-LowHur	Yes	No offsets planned in 2001 - zonal contribution definition	\$6,000	N	TOOH w/tbg	NA	3/20/2001		129.3	37	37	NA	3/30/2001	168	220	3530	589	4125 / 4130	9093		68179	Maxton 25%, Big Lime 10%, Berea/Upper Shale 42%, Lower Shale 23%	Re-ran tbg w/ SN at original depth.	
								TOOH w/tbg; swb		3/21/2001	219'	4.8 wtr															
18	Chesapeake Mineral B-39	1619582986	US-LS	Yes	6 offsets planned in 2001 - zonal contribution definition	\$6,000	Y	TOOH w/tbg	NA	3/16/2001		SS 17.5 DS 33.4		28	28	NA	3/26/2001	41	25	4114	129	4249 / 4318	7568		40.4	Interpretation is very difficult due to low volume & fluid falling on spinner.	Re-run single string of 2 3/8" tbg w/ SN @ 4150'. AFE approved.
								TOOH w/tbg		3/19/2001																	
								Swb		3/20/2001	125'	2.4 wtr / 2.4 oil															
19	Republic Steel Corp. 79	1619579791	US-LS	No	5 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swb	NA	3/22/2001	150'	2.4 wtr	14	35	35	NA	4/3/2001	22	38	4222	44	4289 / 4280			74204	Berea/Upper Shale 60%, Lower Shale 40%	
20	EPC (John Godsey #1) KF 918	1619390840	Clev-LowHur	No	2 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swab	NA	4/3/2001	315'	3.5 wtr	105	70	70	NA	4/5/2001	76	77	3680	135	3799 / 3817			53514	Berea/Upper Shale 100%, Lower Shale 0%	
21	Gibson E. 2 KL 1446	1611990836	BL-Clev-LowHur	No	3 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swab	NA	4/2/2001	148'	3 oil	60	20	20	NA	4/5/2001	64	71	2454	44	2518 / 2525			47002	Berea/Upper Shale 30%, Lower Shale 50%	3 perfs covered w/debris.
22	KF 4448 (Harve Johnson)	1607191151	BL-Clev-LowHur	No	3 offsets planned in 2001 - zonal contribution definition	\$3,500	Y	Swab	NA	4/3/2001	474'	10 oil	39	45	45	NA	4/6/2001	65	68	3655	219	3903 / 3905			54791	Big Lime 18%, Berea/Upper Shale 58%, Lower Shale 24%	May need tbg.
23	KF 1604 (W.D. Hall)	1611991031		No	0 offsets planned in 2001 - zonal contribution definition	\$3,500	N	Swab	NA	3/30/2001	323'	16 wtr	33	73	73	NA	4/4/2001	38	50	2924	299	3248 / 3256			36.5	Weir 15%, Berea/Upper Shale 75%, Lower Shale 10%	

**TOTAL COST ESTIMATE OF  
PRODUCTION LOGGING  
PROGRAM:**
**\$258,500**